ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

DECISIONS

1988

DECISIONS

ISSUED IN 1988

NUMBER	APPLICATION NUMBER	TITLE	DATE OF ISSUE
D 88-1	871056	PEACE RIVER EXPANSION PROJECT PREP II SHELL CANADA LIMITED	25 JANUARY 1988
D 88-2	871411	WOOD WASTE POWER PLANT CALLING LAKE AREA SOUTHVIEW FIBRE TECH LTD.	25 MARCH 1988
D 88-3	871943, 871913, 872057	BATTERY/COMPRESSOR APPLICATION PIPELINE APPLICATIONS CYGNET FIELD RANCHMEN'S RESOURCES LTD.	16 MARCH 1988
D 88-4	871928	APPLICATION FOR A WELL LICENCE JOFFRE FIELD BONANZA OIL & GAS LTD.	11 MAY 1988
D 88-5 Interim	871983	APPLICATION FOR A PUMP STATION AND RELATED FACILITIES IN THE LA COREY AREA AEC PIPELINES	26 APRIL 1988
D 88-5	871983		14 JULY 1988
D 88-5 Amendment	871983		26 JULY 1988
D 88-6	870593	EXPANSION OF THE SYNCRUDE MILDRED LAKE OIL SANDS PLANT	30 MAY 1988
D 88-7	870593	SYNCRUDE EXPANSION MILDRED LAKE OIL SANDS PLANT	3 JUNE 1988
D 88-8	871060	GAS PLANT EXPANSION POUCE COUPE FIELD CHEVRON CANADA RESOURCES	17 JUNE 1988
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D 88-9 Interim	871435 AND 880727	GAS PROCESSING FACILITIES IN THE ACHESON FIELD CHEVRON CANADA RESOURCES ICG RESOURCES LTD.	7 JULY 1988
D 88-9	871435 AND 880727	GAS PROCESSING FACILITIES IN THE ACHESON FIELD CHEVRON CANADA RESOURCES LIMITED ICG RESOURCES LTD.	11 AUGUST 1988

D 88-10	870612	APPLICATION TO CONSTRUCT AN OIL SANDS DREDGING PROJECT C-H SYNFUELS LTD.	24 JUNE 1988
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D 88-14	880499 AND 880920	REQUEST FOR BOARD ORDER OF A WELL ABANDONMENT MANALTA COAL LTD. APPLICATION FOR PERMIT FOR PIPELINE CONSTRUCTION CHINOOK MANAGEMENT LTD.	16 NOVEMBER 1988
D 88-15 Interim	880984, 880985, 880986, AND 880988	APPLICATIONS FOR WELL LICENCES ACHESON EAST FIELD WESTHILL RESOURCES LIMITED	16 SEPTEMBER 1988
D 88-15	880984, 880985, 880986, AND 880988	APPLICATION FOR WELL LICENCES ACHESON EAST FIELD WESTHILL RESOURCES LIMITED	16 SEPTEMBER 1988
D 88-16	880557	APPLICATION FOR A WELL LICENCE WATERTON FIELD SHELL CANADA LIMITED	22 DECEMBER 1988
D 88-17	870705	GAS REMOVAL PERMIT AMENDMENT PAN-ALBERTA GAS LTD.	26 OCTOBER 1988
D 88-18	881276	APPLICATION FOR A WELL LICENCE PROVOST FIELD LADD EXPLORATION COMPANY	25 NOVEMBER 1988

DECISIONS
1988

NUMBER	APPLICATION NUMBER	TITLE	ISSUED TO DEPARTMENT DATE
D 88-17	870705	GAS REMOVAL PERMIT AMENDMENT PAN-ALBERTA GAS LTD.	K. FISHER GAS 26 OCTOBER
D 88-18	881276	LADD EXPLORATION COMPANY APPLICATION FOR A WELL LICENCE PROVOST FIELD	V. VOGT DRILL.&PROD. 25 NOVEMBER
D 88-19	880963	TRANSALTA UTILITIES CORPORATION 138-KV TRANSMISSION LINE FACILITIES NORTH LETHBRIDGE-TEMPEST AREA	P. FORBES HYDRO & ELECTRIC 2 FEBRUARY 1989
D 88-20	880983	DOME PETROLEUM LIMITED WELL LICENCE APPLICATION WATERTON FIELD	S. RICHARDSON DRILL.&PROD. 1 FEBRUARY 1989
D 88-21		CANCELLED	
D 88-22	861041	NORCEN ENERGY RESOURCES LIMITED APPLICATION FOR APPROVAL OF A GAS PROCESSING FACILITY IN THE CAMPBELL-NAMAO FIELD	M. SEMCHUK GAS 19 JANUARY 1989
D 88-23	870772	UNIVERSAL EXPLORATIONS LTD. GAS PROCESSING PLANT HUSSAR, WINTERING HILLS, AND SEIU LAKE FIELDS	E.MOELLER GAS 12 JANUARY 1989
Memo of Decision	871318	Planning Meeting on Ethane Policy Implementation	8 Sept. 1987
D 88-D		Alberta Ethane Policy Report on Implementation	April 1988

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SHELL CANADA LIMITED
PEACE RIVER EXPANSION PROJECT
PREP II

Decision D 88-1
Application 871056

1 APPLICATION

Shell Canada Limited (Shell) applied on 20 July 1987, pursuant to sections 10(1) and 11(1) of the Oil Sands Conservation Act, to amend Approval No. 4389 to provide for a second major phase of its commercial in situ oil sands scheme referred to as the Peace River Expansion Project (PREP). The proposed second phase (PREP II) would add a reservoir development area of approximately 3000 ha and average bitumen production rate of 6400 cubic metres per day (m^3/d) thereby increasing PREP production to 8000 m^3/d. Using the pressure cycle steam drive process over a 30-year operating life, recovery from the Bluesky-Gething oil sands deposit is predicted to be 55 per cent of the bitumen in place.

Adjunct information respecting environmental impacts and mitigative measures, including applications to Alberta Environment for permits and licences under the Clean Air Act and Clean Water Act, land conservation and reclamation procedures, and socio-economic impacts associated with the project were also filed.

In order to obtain an early indication of any public or industry concerns respecting the application, the Board published a Notice of Filing on 10 August 1987. The Whitefish Lake Indian Band No. 459 (the Band) identified concerns related to native employment and business opportunities. The Band initially requested a public hearing concerning certain aspects of the application; however, the request was withdrawn on the basis of certain undertakings by Shell.

Fording Coal Limited (Fording) identified coal as an alternative long-term source of fuel for raising steam. While Fording did not oppose the granting of the application, it proposed that as a condition of the approval Shell should be required to participate in a research project involving the pilot testing of a coal-fired steam generator.

These submissions are dealt with in more detail in later sections of this report.

2 SPECIFIC DETAILS

The details of PREP II are summarized below:

- o PREP II would be built as an integrated, stand-alone facility, with the central processing plant located 4 km south of PREP I, as shown on the attached figure, surrounded by the field area.

- PREP II would recover 6400 m^3/d crude bitumen over a 30-year period representing a recovery estimated by Shell to be 55 per cent of the initial bitumen reserves in place.

- The pressure cycle steam drive process, developed at the experimental project (Peace River In Situ Project, PRISP) and continued at PREP I, would also be used at PREP II.

- PREP II would be developed in four annual construction stages, each capable of producing 1600 m^3/d bitumen.

- Directional drilling from satellite pads would be utilized to minimize land use impact. A total of 8 satellites and 212 wells would be required for each 1600 m^3/d stage. Productivity over the 30-year life of the project would be maintained via the addition of four further stages at approximately year 10 and four more at year 20.

- A total of 16 steam generators would be initially installed on the basis of 4 generators being required for each of the four stages.

- The central processing plant would be built in two increments of 3200 m^3/d.

- PREP II water, power, and natural gas fuel requirements would be obtained via tie-in to the existing PREP I lines, and the diluted PREP II bitumen product would be shipped through existing facilities located at PREP I. A new pipeline would be necessary to bring the required diluent requirements to both PREP I and PREP II. The exact route for the pipeline has not yet been selected; however, Shell will utilize existing pipelines and pipeline corridors where possible and would be subject to regulatory approval.

- Produced water would be de-oiled with induced gas flotation and filtration; water that is to be reused would be blended with fresh water and softened with two stages of ion exchange. Following an initial test period, reuse of up to 70 per cent of the combined PREP I/PREP II produced water is expected with the ion exchange treatment system.

- Fresh make-up water would be obtained from Shell's existing facility on the Peace River.

- A gas processing facility, designed to recover 94 per cent of the sulphur from the combined PREP I/PREP II poor-quality acid gas stream, would be constructed at the PREP II Central Processing Plant site, following which a maximum of 2 tonnes per day of sulphur would be released to the atmosphere via an incinerator stack.

- The project capital cost is estimated at $570 million, with annual operating costs of approximately $100 million. A further $330 million would be required every 10 years to replace depleted wells and extend field gathering facilities. (All figures are 1987 dollars.)

- Initial project construction of the central processing facility, to occur over 18 months, is estimated to create an average 400 jobs, peaking at 650 jobs. During the 30-year operation phase, 280 new jobs would be created on site plus 25 technical/administrative support jobs in Calgary.

The Board has reviewed the details of the project, and is largely satisfied that the program to implement the PREP II is sound, orderly, and in the public interest. However, it has identified the following matters which it believes to be of particular interest and comments on these aspects in subsequent sections of the report.

- Socio-economic Impacts
- General Environmental Details
- Local Employment Opportunities
- Make-up Fuel Source

3 SOCIO-ECONOMIC IMPACTS

Through a series of meetings and open house programs, Shell presented preliminary details of the commercial project expansion to community representatives, business, public interest and native groups, and government agencies. Comments regarding actual impacts that occurred as a result of PREP I, and anticipated impacts due to PREP II, were solicited. Perceptions about PREP II were largely positive with few concerns mentioned. As with the PREP I application, some concern regarding local employment and business opportunities for natives was expressed. These concerns are discussed in more detail in section 5 of this report.

Although final commitment to the development of PREP II is dependent on crude oil price forecasts and other economic factors, Shell is optimistic that it will become economically viable and has therefore proceeded with preliminary engineering design. Commitment to detailed engineering and pre-construction field work could be made as early as 1988 if projections of crude oil prices are favourable and satisfactory agreements concerning royalties, taxes, and other commercial matters are finalized.

The Board appreciates the difficulties in making firm commitments to project construction in the face of recurring uncertainty respecting long-range future oil prices. However, orderly and efficient development of the oil sands would be seriously hampered without firm commitments by project sponsors. In addition, the criteria for assessing the public interest and the applicability of the project equipment and technology often change as time passes.

Keeping all these factors in mind, the Board considers it desirable to grant approval for PREP II with a lapse date in the approval. The Board believes a period of about 3 years (ie. up to 31 December 1990) is suitable for this purpose, after which approval of PREP II would lapse and be cancelled if substantial project construction was not then under way.

4 GENERAL ENVIRONMENTAL DETAILS

Shell is confident that the proposed commercial project expansion would develop the oil sands resources in a manner consistent with effective conservation practices and minimal environmental impact. All regulations governing the environment and resource use would be complied with. Co-operation with various government departments regarding regional plans and objectives would continue. All construction and operation activities would be undertaken so as to avoid or minimize undesirable biophysical environmental impacts. Furthermore, because of the staged development, these disturbances would be spread over the project life. Specific environmental details are summarized below:

- A sulphur recovery facility consisting of a Gas Sweetening Unit (GSU) and a Sulphur Recovery Unit (SRU) will be installed to recover sulphur from the PREP I and PREP II produced gas streams.

- The overall sulphur recovery level of the facility will be 94 per cent of the sulphur in the poor-quality (low H_2S concentration) produced gas stream, with a maximum of 2 tonnes per day of sulphur emission following start-up of the gas processing facility. However, because of "turndown" limitations, sulphur recovery would not commence until some 2.5 years after commencement of production from PREP II. Prior to that time, sulphur emissions would gradually climb but would not exceed 10 tonnes per day.

- The PREP II steam generator stacks and the incinerator stack have been sized to ensure that ground-level SO_2 concentrations from the overall complex remain below the applicable ambient air quality standards.

- Hydrocarbon vapours will be collected from tanks and low-pressure equipment by a vapour recovery system. The vapours will be compressed and discharged to the produced gas system. Casing vent gas from the field will also be collected, compressed, and discharged to the produced gas system.

- Produced solids will be trucked to a clay-lined containment pit to ensure that there is no contamination of the surrounding ground water and will ultimately be disposed in an environmentally safe manner following approval from the appropriate government agencies.

- Approximately 850 ha of land will be cleared for PREP II which includes about 400 ha of surface disturbance for drilling, disposal, and surface facilities.

- Increased water withdrawal from the Peace River will take less than 0.1 per cent of the lowest recorded flow during the period of maximum requirement. The use of Peace River water will decline as water reuse objectives are achieved.

The Board is satisfied that the environmental impacts of the project are acceptable. Furthermore, the phasing of the project provides an opportunity for adjustments and improvements in operating details and equipment design to minimize impacts. In addition, monitoring requirements included in permits and licences under the Clean Air Act and Clean Water Act would ensure that emissions are kept to acceptable levels.

5 LOCAL EMPLOYMENT OPPORTUNITIES

In keeping with its policies of first preference hiring of qualified local residents and of maximizing native training and employment opportunities, Shell plans to continue to assist local business by providing information and discussing opportunities for the supply of goods and services related to the project. Shell intends to continue providing information programs and assistance to the local community respecting employment opportunities in construction and operation jobs.

The Whitefish Lake Indian Band No. 459 raised concerns respecting training, employment, and contracting opportunities for its members. Shell met with representatives of the Band to discuss those concerns and has undertaken certain initiatives to better define and promote the opportunities available to the Band with regard to employment and business. As a result of these undertakings, the Band withdrew its intervention.

The Board is satisfied with the commitments and initiatives made by Shell with respect to business and employment opportunities for the local community.

6 MAKE-UP FUEL SOURCE

Fording Coal Limited (Fording) filed a submission with the Board respecting the use of coal versus natural gas as the fuel for the steam generators. Fording observed that fuel costs will be one of the largest operating expenses during the life of the project. Therefore, it contended that alternative fuel sources, specifically coal versus natural gas, should be considered. Fording was concerned that the oil industry in general has not field tested coal-fired equipment and therefore had no operating experience on which to base its contention that gas would be the more economical fuel over the longer term.

Fording therefore recommended that Shell be required to participate in a demonstration test of coal-fired steam generators so that Shell would be able to provide an accurate economic analysis of fuel alternatives for future installations of steam generators.

Shell indicated that it had no objection to evaluating any specific proposal for participation in a research project for use of coal-fired steam generators; however, it did not believe that the Board should make participation in such a project a condition of an approval for PREP II.

The Board has reviewed the economic aspects of natural gas versus coal as alternate fuels for PREP II and accepts that the economic advantage currently rests with natural gas.

Respecting the technology for coal use, the Board notes that there have been advances in the development of modular coal-fired steam generators in a size range comparable to the gas-fired units currently in use at PREP I. However, these units would have to be tested under field conditions to demonstrate the turndown ranges required for in situ oil sands operations.

The Board believes that coal-fired steam generation could become economically attractive over the longer term. Bearing that in mind and recognizing the potential public benefit of expanded use of Alberta's vast coal resources, the Board endorses Fording's proposal that oil sands operators actively support field demonstration testing of coal-fired steam generation. The Board understands that the Alberta Office of Coal Research and Technology is currently designing such a test. The Board expects that Shell, as well as other oil sands operators, will find it advantageous to participate in that or an equivalent demonstration test at the earliest available opportunity.

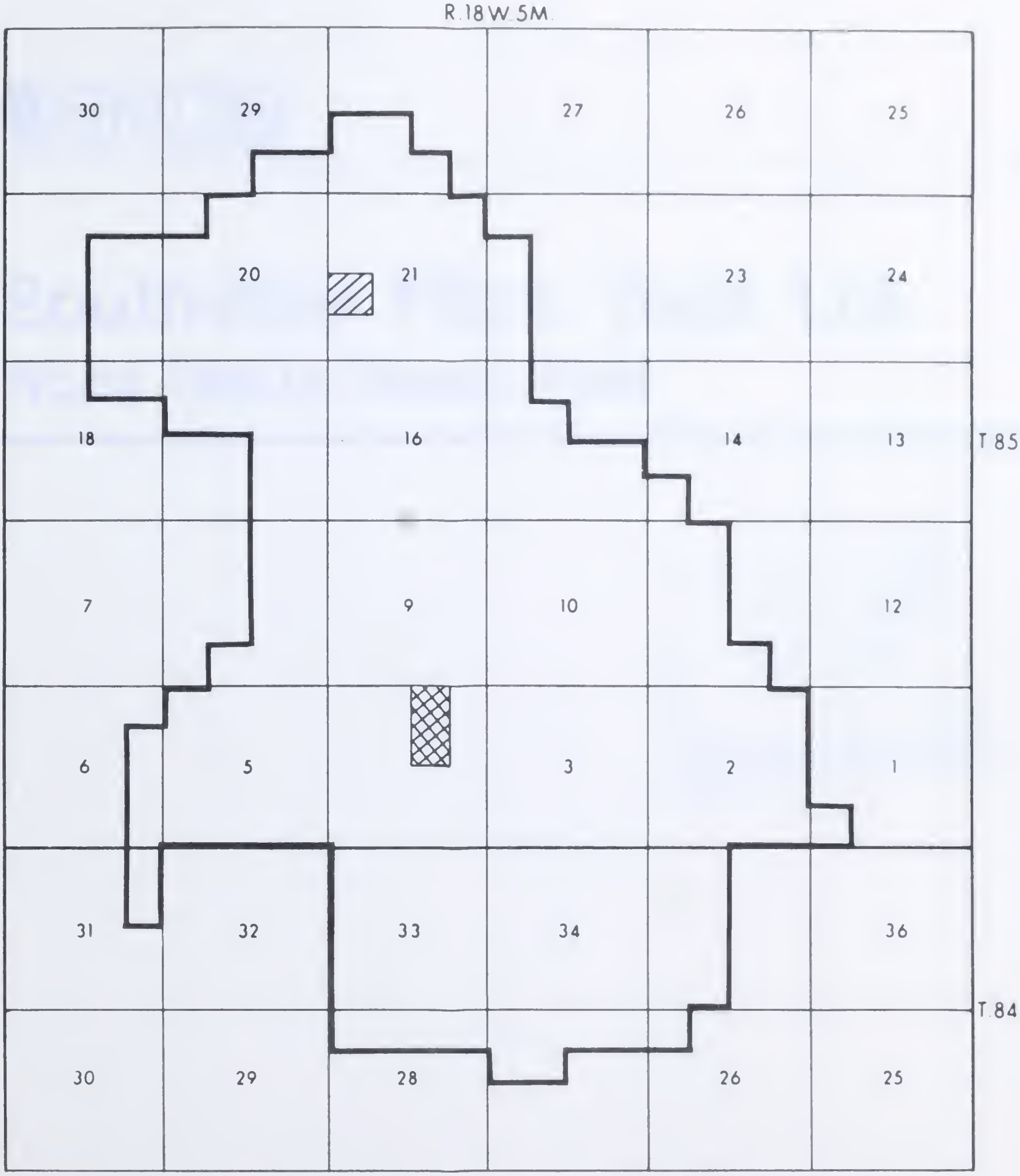
7 DECISION

Having reviewed the details of the proposed commercial project expansion, and having regard for the potential impacts and public benefits, the Board is prepared, with the authorization of the Lieutenant Governor in Council, to approve Application No. 871056 for Peace River Expansion Project II, with provision for cancellation if substantial construction is not under way by 31 December 1990.

DATED at Calgary, Alberta on 25 January 1988.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom
Vice Chairman



PREP central processing facility

PREP II central processing facility

PEACE RIVER EXPANSION PROJECT II
SHELL CANADA LIMITED
APPLICATION NO. 871056

D 88-1
ERCB

ERCB

Southview Fibre Tech Ltd.

Wood Waste Power Plant

March 1988

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ERCB

Southview Fibre Tech Ltd.

Wood Waste Power Plant

March 1988

SOUTHVIEW FIBRE TECH LTD.

MARCH 1988

Published by:

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Telephone (403) 297-8311

PRICE: $10.00

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SOUTHVIEW FIBRE TECH LTD.
WOOD WASTE POWER PLANT
CALLING LAKE AREA

Decision D 88-2
Application 871411

1 BACKGROUND

1.1 Application

Southview Fibre Tech Ltd. applied to the Energy Resources Conservation Board (ERCB), pursuant to sections 17(2)(a), 17(2)(b), 17(2)(c), and 17(5) of the Hydro and Electric Energy Act (Act),

(a) for approval to connect a 30-megawatt (MW) wood-burning power plant with the electric system of TransAlta Utilities Corporation, and

(b) to establish the basis for determining the price of power and energy to be sold to TransAlta Utilities Corporation.

The overall development (which is not a part of this application) was identified as the Athabasca Agro-Industrial Complex, would be located in the Calling Lake area, and would consist of

(a) a 30-MW, wood-fired steam generator power plant, and

(b) a cattle-feed operation using steam and electricity to convert aspen wood chips into cattle feed.

The power plant would have a planned nominal capacity of 30 MW and an operating life of 20 years. The main fuel for the power plant would be waste wood purchased from sawmill operators in the Athabasca/Calling Lake area.

1.2 Hearing

The application, received on 18 September 1987, was originally scheduled to be considered at a public hearing on 19 October 1987, but was adjourned at the request of the applicant in order that it could amend its original application. The amended application was submitted to the Board at the end of November 1987. Following circulation of the amended application to interveners, the public hearing was re-opened on 21 January 1988 with C. J. Goodman, P.Eng., F. J. Mink, P.Eng., and N. W. MacDonald, P.Eng., sitting.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Southview Fibre Tech Ltd. (Southview) R. F. Roddick	D. R. Branchcomb J. A. MacMillan M. Smith
County of Athabasca #12 (Athabasca) G. B. Scott	J. Woodward
TransAlta Utilities Corporation (TransAlta) J. J. Marshall, Q.C. C. Dahl Rees	W. Saponja, P.Eng. T. Crowe, P.Eng. N. Brausen, P.Eng. W. K. Taylor D. L. Hawkins, P.Eng.
Alberta Power Limited (Alberta Power) C. K. Sheard	J. R. Frey, P.Eng. R. V. Baer, P.Eng.
Industrial Power Consumers Association of Alberta (IPCAA) A. G. MacWilliams	
City of Edmonton (Edmonton Power) J. B. Marshall	
City of Calgary R. F. Goss	
Cities of Red Deer/Lloydminster (Red Deer-Lloydminster) J. A. Bryan, Q.C.	
Energy Resources Conservation Board staff C.J.C. Page M. L. Asgar-Deen, P.Eng. A. Kwaczek R. L. Schroeder	

The City of Lethridge and W. Arsene filed submissions but did not appear at the re-opened hearing on 21 January 1988.

2 DEFINITION OF THE ISSUES

After consideration of the evidence respecting this application, the Board believes the issues to be

- o need for the connection,
- o location of the connection,
- o principles of avoided cost determination,
- o avoided cost parameters, and
- o prices and principles of price determination.

3 NEED FOR THE CONNECTION

3.1 Views of the Applicant

Southview stated that recently published (1987) documents by the North American Electric Reliability Council show that, based on information supplied by TransAlta, generating capacity beyond the currently-approved units will not be required on the Alberta interconnected system (AIS) until 1994. Accordingly, it based its application on the assumption that a new coal-fired unit would be required in 1994.

While recognizing the current surplus capacity, the applicant stated that the power plant portion of the Athabasca Agro-Industrial Complex should be allowed to be commissioned in advance of the actual need for additional capacity on the AIS. Early start-up is required in order for the utilities to properly recognize this facility when planning for new capacity additions in 1994. The facility would also provide operational data on how independent power facilities could be integrated with the other generating units on the AIS. There would also be benefits to the AIS in terms of fuel diversity, geographic diversity, and the ability to better match capacity additions to load growth. Finally, the project is in the public interest if such public interest is defined as being broader than matters of cost of electricity alone. The applicant stated that there would be positive employment and income impacts for Athabasca which in turn benefit the province as a whole and which should be recognized.

3.2 Views of the Interveners

Athabasca fully supported the Southview application. It stated that the project is very much in the public interest when such interest is defined more broadly than simply rates to consumers. The benefits to Athabasca would include a larger tax base as well as positive impacts on income and employment. Athabasca further submitted that such economic benefits should be considered in the decision.

TransAlta stated that there is a great deal of uncertainty surrounding forecasts of load growth and that additional capacity beyond the currently-approved units would not be required on the AIS until 1993 at the earliest, and possibly as late as 1998. A most likely scenario would involve additional capacity over the 1994/95 winter peak. In addition, TransAlta submitted that the information used by Southview is out of date since current plans show a need for the addition of two 100-MW gas turbines in 1994 and one 400-MW coal-fired unit in 1995.

TransAlta stated that, in view of the uncertainty surrounding electric load forecasts, 1995 is the earliest date for which it would be willing to make irrevocable commitments for new capacity.

Alberta Power noted that there will be surplus capacity on the AIS for some time and that the latest available data indicates the need for additional capacity in 1994. It did indicate, however, that it supported the connection of any project that would lower the cost of electricity to consumers of Alberta.

IPCAA and Edmonton Power provided no views on the timing of capacity additions to the AIS, although Edmonton Power noted TransAlta's position that two 100-MW gas turbines would be needed in 1994.

The City of Calgary indicated that there is no need for additional capacity on the AIS until at least 1994. It opposed Southview's application because need for capacity had not been demonstrated. The City also stated that Southview had not demonstrated that the inclusion of its project in the AIS would be in the public interest. As well, it contended that a connection should not be approved unless it would benefit all consumers in the province.

Red Deer-Lloydminster noted that this application is proceeding in a reverse order since the connection application is preceding a plant application. They stated that, since need is generally dealt with in the plant application, the current order of processing precludes any discussion on need. Red Deer-Lloydminster stated that there is no need for additional capacity on the AIS at this time and the granting of an order to connect would give a tacit endorsement to additional surplus capacity on the system. This may be difficult for consumers to understand in view of the deferrals granted to units currently under construction. They also stated that the ERCB's mandate does not include resolving socio-economic issues which may exist within the province.

3.3 Views of the Board

The Board recognizes that there is no need for additional capacity on the AIS at this time. However, having regard for economic, orderly, and efficient development, the Board considers that it could be in the public interest and to the benefit of all utility customers if an independent power producer could supply electricity to the AIS at a lower cost than conventional AIS generation. Accordingly, the Board considers it necessary to determine AIS costs which could be avoided by the Southview project.

The Board accepts the view expressed by most of the participants that additional capacity beyond the currently-approved units may be required on the AIS in the 1994/95 time frame. However, it also notes that, depending on actual load growth, new capacity may not be required until 1998. Given the circumstances and outlook for future plant additions, the Board considers it appropriate to adopt 1995 as the most likely time frame and, therefore, the reference point for future additional

utility plants that potentially could be deferred by the proposed Southview power plant.

Some interveners expressed concern that the usual order for processing applications has been reversed in the Southview case. While this process is not desirable, the Board agreed to accommodate the applicant and hear the connection application first in order to provide Southview with information it said it needed to proceed with funding and financing plans. This reversal of order to accommodate Southview is not typical and does not circumvent the legislative requirements for application approval of all stages of project development. The Board expects and Southview recognizes that a potential approval to connect the Southview plant is contingent on the filing of an application for approval of the facilities and subsequent approval.

4 LOCATION OF THE CONNECTION

4.1 Views of the Applicant

Southview indicated that the exact location of its power plant has not been established, but it would probably be located in the Calling Lake area. It also indicated that a transmission line would have to be built from TransAlta's Colinton substation to connect Southview's plant with the AIS. The costs of the transmission line would be borne entirely by Southview.

The applicant plans to call for bids for the construction of the line, with a requirement that the line be built to TransAlta's specifications. Southview proposed that TransAlta be given the responsibility of maintaining the line after construction.

Southview stated that details of the plant and related transmission line would be submitted in a future application.

4.2 Views of the Interveners

TransAlta agreed with Southview that the most probable location of a connection would be at TransAlta's Colinton substation. It indicated that any transmission line would have to be built to TransAlta technical specifications prior to being connected to the AIS.

Alberta Power took no position on the question of whether or not connection between Southview and TransAlta should take place nor did it comment on the location of the connection.

The City of Calgary said that it is premature, at this time, to issue Southview an order to connect without first approving the plant.

Red Deer-Lloydminster contended that any costs associated with building a new transmission line and connection should be paid by Southview.

The remaining interveners did not express any views on the location of the connection.

4.3 Views of the Board

The Board notes that the precise location of Southview's power plant has not been established, but accepts Southview's statement that it will probably be located in the Calling Lake area north of the town of Athabasca. The Board understands that TransAlta's Colinton substation is the nearest major switching facility in the area and expects that it would be the connection point between Southview's power plant and the Alberta electrical system. The Board agrees with Southview that future applications would need to provide details of the plant and transmission line.

The Board notes that connection of Southview's proposed plant to the AIS would be subject to the plant meeting specifications and performing according to the general descriptions provided in this application and Southview receiving approval of the detailed plant application. Also, Southview will require a permit and licence from the Board for approval to construct the transmission line, and would have to negotiate with landowners wherever the line is not on Southview's land.

5 PRINCIPLES OF AVOIDED COST DETERMINATION

5.1 Views of the Applicant

Southview submitted that the proxy plant methodology should be used to determine AIS avoided costs, based on additional capacity being needed on the system in 1994. It stated that this method is relatively easy to implement and provides a fair reflection of the costs which would ultimately be avoided by TransAlta. In the period prior to 1994, when capacity is not needed, avoided costs should be the AIS marginal energy costs.

Southview stated that a single rather than a composite proxy unit should be used because the planned facility would be operated as a single base-load unit. Accordingly, in its application, Southview based its avoided costs on its calculation of AIS marginal energy costs up to 1994 and the costs associated with a base-load coal-fired plant for 1994 and thereafter. The applicant indicated that it would not expect the avoided cost calculations to be open to review once determined. However, it would consider a formula that reflected actual rather than forecast inflation rates.

In its application, Southview argued that various items should be included in the avoided cost calculation to leave the electric consumer indifferent with respect to cost of service. In general, the costs to be avoided relate to the cost of an Electric Utility Planning Council (EUPC) generic coal-fired unit. Southview submitted that in addition to these, connection costs and pollution control costs associated with the generic unit and line losses should be considered. While line

losses were included in the proposal as a specific figure, Southview said that these could be handled on a formula basis and determined after the plant site is chosen. The applicant also stated that income taxes should be considered avoidable in their entirety, regardless of the existing tax rebate situation.

The applicant took issue with the AIS marginal energy costs as calculated by TransAlta and Alberta Power. It submitted that the vertical integration of the utilities allows them to capitalize many costs relating to coal mining which should be considered variable as opposed to fixed. Further, the Southview facility would allow less intensive mining of existing sites, thereby reducing costs and allowing deferral in development of new mines. Consequently, Southview considered the AIS variable energy costs submitted by the utilities to be low.

Southview rejected the Fuel Offset Method proposed by TransAlta as being an inappropriate way in which to calculate avoided cost. It maintained that new facilities would cost substantially more than present estimates of avoided cost calculated using this method.

5.2 Views of the Interveners

Athabasca supported Southview's method of determining avoided cost.

TransAlta stated that any compensation payable to Southview should be based on AIS avoided costs and recommended that the Fuel Offset Method be used to determine these costs. This method was advocated over the Proxy Plant Method primarily because it removes any error that may result from using an inappropriate proxy unit. TransAlta noted that the Fuel Offset Method considers generation and load of the AIS rather than just the costs associated with a specific unit. Using this method, avoided energy costs are determined annually as the average hourly system marginal costs, negating the need to forecast long-term fuel escalation rates. Avoided capacity costs would begin in 1995 and would be based on the least-cost source of capacity, currently assumed to be a gas turbine. Although it supports the Fuel Offset Method, TransAlta stated that, if the Board chooses a proxy plant approach, the nature of the proxy unit should be addressed. Specifically, TransAlta stated that a composite unit, comprised of a gas turbine peaking unit and a coal-fired base-load unit, would be more appropriate than a single unit since it would better represent the mix of facilities that exist or are planned for the AIS. With this methodology, avoided energy costs prior to 1995 would be based on the system marginal costs. Beginning in 1995, the avoided energy and capacity costs would reflect the costs of the composite unit.

TransAlta took issue with some of the parameters assumed by Southview in its calculation of avoided costs. It argued that Southview's estimate of the AIS marginal costs was overstated. Further, the inclusion of pollution control costs overestimates the cost of meeting current

environmental standards which can be met without any flue-gas desulphurization equipment. TransAlta also assumed no impact on transmission line losses although it would be willing to examine this issue once a final plant site is chosen. TransAlta indicated that, since the purpose of the avoided cost exercise is to keep consumers indifferent to where the power is produced, the rebated portion of income tax paid should not be considered avoidable. It did not, however, take issue with the inclusion of interconnection costs.

Alberta Power noted that the ERCB could establish broad guidelines or an appropriate methodology to determine avoided costs. One possible approach would be the single Proxy Plant Method. This method has the advantage of being easier to understand conceptually. However, it relies on long-term forecasts and must focus on a single unit, whereas the growth in the AIS will likely be met by a mix of facilities. In this regard, Alberta Power considered the composite proxy to be an improvement.

Alberta Power stated that energy and capacity components should be determined separately. It also expressed concerns over some of the assumptions and cost items used by Southview to determine avoided cost. The inclusion of pollution control costs was not considered appropriate since it is almost certain that the next few units will not require any flue-gas desulphurization or any additional emission control equipment. It noted that, even if some equipment is required, there are lower cost options available relative to that assumed in Southview's analysis. Alberta Power also stated that the AIS marginal costs used in the Southview proposal were overestimated for the period 1989 to 1993. Concerning the question of income taxes, Alberta Power said the rebated portion should be excluded from avoided cost regardless of the tax situation of the developer because it is simply not a cost to consumers. Further, Alberta Power would exclude interconnection costs.

Alberta Power said that the impact of a project on system line losses should be included in the analysis once such an impact could be determined. It also suggested that any deferral of transmission lines should be considered in the avoided cost calculations.

Neither IPCAA nor the City of Calgary took a specific position with respect to the determination of avoided cost although IPCAA stated that the decision with respect to Southview should be generally applicable to all non-utility generation and should be consistent with the recommendations of the Small Power Inquiry Report.

Edmonton Power indicated that, if the ERCB considered a proxy plant methodology to be an appropriate way to determine avoided cost, the proposal put forth by the applicant contains some flaws. One flaw it singled out was the assumption that the next unit added to the system would be a coal-fired plant. It noted that TransAlta's evidence indicated the next unit would be a gas turbine. Further, the costs used by Southview are a blend of first and second units whereas the next unit is likely to be the addition of a third unit to an existing facility.

Red Deer-Lloydminster indicated support for the proxy plant approach to avoided cost estimation. However, they considered the analysis as presented by Southview to be flawed and supported the corrections as put forth by TransAlta and Alberta Power. They further stated that the rebated portion of income taxes should be excluded from the calculation of avoided cost.

5.3 Views of the Board

The Board considers that the relevant Alberta interconnected electric system costs to be determined are the costs that the utilities would avoid, thereby leaving the utility customers indifferent, as a result of the connection of the Southview plant. Whatever process is chosen, the consumers should not face any cost increase beyond what they normally would have faced in the absence of the Southview project.

The Board recognizes that there are several possible ways to determine avoided cost but it believes that the method ultimately chosen should be simple yet accurate. The tradeoffs between simplicity and accuracy are reasonable if the principle of avoided cost is maintained. The Board believes that the Proxy Plant Method would meet the criteria of simplicity and accuracy, and therefore accepts this methodology for the determination of avoided costs.

The Board believes that capacity costs can only be avoided at the time of need for new capacity and it recognizes the uncertainty surrounding the timing of the next capacity addition to the AIS. The Alberta electric system is planned with a combination of peaking and base-load facilities. As indicated by the evidence presented, during the mid-1990s both types of capacity will likely be required on the AIS. Southview's proposed facility has the potential to defer such capacity and the Board is of the view that any capacity costs that it avoids should reflect this composite capacity. Therefore, the fixed costs of a kilowatt of avoided capacity can be approximated using 75 per cent of the fixed cost of a 375-MW coal plant and 25 per cent of the fixed cost of a 100-MW gas-fired combustion turbine in 1995. The Board notes that a base-load to peak-load ratio of 75:25 is consistent with the EUPC preferred generation mix objective.

The Board accepts the EUPC cost data for a generic coal unit and a combustion turbine as the basis for calculating avoided fixed costs. These costs do not include any investment in flue gas desulphurization equipment. The Board does not believe such costs should be included in the avoided costs calculation as units installed in the short to medium term should be able to satisfy current environmental standards without special equipment to remove sulphur dioxide from stack gases.

The Board recognizes that the mix of capacity on the AIS does not carry over into energy production. That is, although the system may be planned for a base-load to peak-load ratio of 75:25, energy production will tend to be primarily from base-load facilities. This can be approximated with a 90:10 ratio for the avoided energy cost

calculations. The Board therefore adopts this simplification and energy costs are to be determined on the basis of 90 per cent of the cost of coal-fired and 10 per cent of the cost of gas-fired energy production. Although this simplification will not capture the precise AIS energy mix in any given year over the long term, the Board accepts it as representative for the period under consideration and has chosen to use this simplified method to estimate avoided energy costs for the AIS beginning in 1995.

The Board does not believe that total income taxes paid should be considered as an avoided cost as virtually all of this is rebated to consumers. Only the portion of income taxes which is not rebated should enter the calculation to determine the cost avoided.

Southview has not as yet indicated where the plant would be located. Consequently, the Board considers the inclusion of transmission line losses in the avoided cost calculation to be premature. However, inclusion of avoided interconnection costs is appropriate.

6 AVOIDED COST PARAMETERS

6.1 Views of the Applicant

Southview based its avoided cost calculations (in 1987 dollars) on the costs and characteristics of a generic coal-fired unit as estimated by the EUPC. The unit has a nameplate capacity of 375 MW with a maximum continuous rating of 360 MW and a capacity factor of 77 per cent. Southview assumed a plant life of 30 years with the plant going into service in 1989. Also included in the calculation is an avoided interconnection cost of $50 per kilowatt. The other assumptions and parameters used in the Southview analysis are summarized in Table 2. Southview calculated a levelized nominal avoided cost of 5.24 cents/kW·h (see Table 1, column 2), assuming a 20-year contract period and the plant starting in 1989.

6.2 Views of the Interveners

Of the interveners, only Alberta Power and TransAlta presented actual avoided cost estimates. Using the Fuel Offset Method, TransAlta calculated a levelized nominal avoided cost over the 20-year period of 2.4 cents/kW·h (see Table 1, column 6). For the single proxy approach, both utilities adopted the EUPC generic coal-fired unit figures and operating characteristics used by Southview. A plant life of 35 years rather than 30 years was chosen.

TransAlta agreed with Southview and included AIS interconnection costs of $50 per kilowatt for a generic coal unit and a generic gas unit in its avoided cost calculations. Alberta Power did not include any interconnection costs in its analysis.

TransAlta disagreed with many of the cost assumptions used by Southview to determine avoided costs. TransAlta recalculated the Southview analysis using what it considered more appropriate parameters. This resulted in a decrease in the levelized nominal avoided costs from

5.24 cents/kW·h to 2.96 cents/kW·h (see Table 1, Footnote 1) for a 20-year contract starting in 1989.

For its composite proxy illustration, TransAlta used similar EUPC figures for a generic 100-MW gas combustion turbine. A capacity factor of 74 per cent was assumed along with a 25-year plant life. The other assumptions adopted by TransAlta and Alberta Power are shown in Table 2.

Alberta Power expressed some concern about the assumptions used by Southview to determine the levelized nominal cost of 5.24 cents/kW·h. It revised the Southview analysis using what it considered more appropriate parameters. This reduced the nominal 20-year levelized avoided cost from 5.24 cents to 2.71 cents/kW·h (see Table 1, column 4).

6.3 Views of the Board

The Board notes that all participants agreed that cost data for the EUPC generic coal and gas turbine units should be used for determining avoided costs. The Board accepts these costs as being an appropriate basis for estimating costs which could be avoided by the utilities if future plants were deferred by the Southview power plant. It notes that the EUPC figures include property taxes, insurance, and interim replacements. Adding an additional percentage to account for this, as was done in the Southview proposal, is not appropriate. The Board also accepts the Southview and TransAlta estimate of AIS interconnection costs.

The Board recognizes that there was disagreement among the various parties as to possible inflation and cost escalation rates. The Board accepts the uncertainty surrounding such forecasts and recognizes that some assumptions are required to calculate the likely avoided cost of the Southview facility. The Board considers a general inflation rate of 4.5 per cent to be reasonable in light of the participants' positions and also adopts this rate as the likely increase in the cost of labour and materials. The Board also accepts, for coal, a real escalation factor of 2 per cent per annum above the general inflation rate. The latter is consistent with the EUPC assumptions for a generic coal unit. The EUPC gas price forecast appears reasonable and is also adopted.

For the purpose of its avoided cost calculations and for future capital costs, the Board considers it appropriate to use a discount rate of 11.5 per cent, which is in the range of the estimates presented by the participants. The Board considers a debt equity ratio of 50:50 with a return of 9.5 per cent for debt and a composite return of 13.5 per cent for preferred and common equity to be representative of future utility plant operations and has adopted these for the purpose at hand. Provincial and federal tax rates of 15 per cent and 28.8 per cent respectively are assumed which amounts to an aggregate income tax rate of approximately 44 per cent, the figure used by Alberta Power. Of this, only the unrebated portion (approximately 3.3 per cent) is considered part of avoided cost.

TABLE 1 SUMMARY OF AVOIDED COSTS

Column:	1	2	3	4	5	6	7	8	9
		SOUTHVIEW		ALBERTA POWER		TRANSALTA (1)		ERCB	
		Coal Proxy		Revision to Southview's estimates		Fuel Offset Method		Composite Proxy Method	
	Energy (2) GW.h	Avoided Costs cent/kW.h	Total Costs Million $	Avoided Costs cent/kW.h	Total Costs Million $	Avoided Costs cent/kW.h	Total Costs Million $	Avoided Costs cent/kW.h	Total Costs Million $
1989	164.25	2.00	3.29	1.00	1.64	0.98	1.61	0.98	1.61
1990	164.25	2.10	3.45	1.04	1.71	0.96	1.58	0.96	1.58
1991	164.25	2.21	3.62	1.08	1.78	0.92	1.51	0.92	1.51
1992	164.25	2.32	3.80	1.13	1.85	0.99	1.63	0.99	1.63
1993	164.25	2.43	3.99	1.17	1.92	1.23	2.02	1.23	2.02
1994	164.25	6.02	9.89	3.26	5.35	1.67	2.74	1.67	2.74
1995	164.25	6.34	10.41	3.39	5.57	2.86	4.70	3.64	5.98
1996	164.25	6.67	10.96	3.53	5.79	3.03	4.98	3.83	6.29
1997	164.25	7.02	11.53	3.67	6.02	3.13	5.14	4.03	6.62
1998	164.25	7.39	12.14	3.81	6.26	3.37	5.54	4.24	6.96
1999	164.25	7.78	12.78	3.97	6.51	3.64	5.98	4.45	7.32
2000	164.25	8.19	13.45	4.12	6.77	3.80	6.24	4.68	7.69
2001	164.25	8.62	14.16	4.29	7.04	3.93	6.46	4.92	8.09
2002	164.25	9.07	14.90	4.46	7.33	4.16	6.83	5.19	8.53
2003	164.25	9.55	15.69	4.64	7.62	4.39	7.21	5.45	8.95
2004	164.25	10.06	16.52	4.82	7.92	4.64	7.62	5.74	9.42
2005	164.25	10.59	17.39	5.02	8.24	4.91	8.06	6.04	9.92
2006	164.25	11.15	18.31	5.22	8.57	5.19	8.52	6.35	10.44
2007	164.25	11.74	19.28	5.43	8.91	5.49	9.02	6.69	10.99
2008	164.25	12.35	20.30	5.64	9.27	5.81	9.54	7.04	11.56
2009	164.25	13.02							
TOTAL (nominal)			235.84		116.08		106.93		129.84
TOTAL P.V. to 1989 (3)			66.31		33.28		29.51		34.95
Levelized avoided costs (4)		5.24 (5)		2.71		2.36		2.76	

Notes:

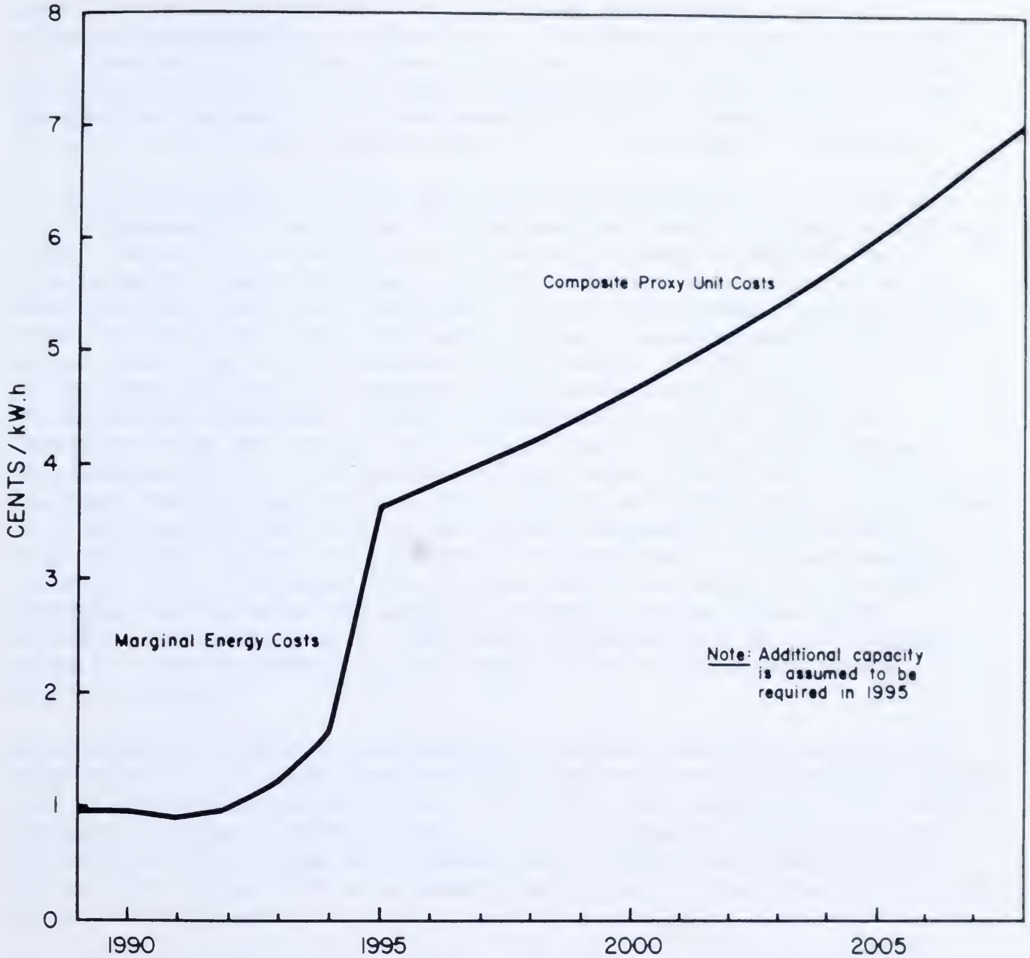
(1) TAU also revised Southview estimates and obtained a levelized cost of 2.96 cent/kW.h It also calculated levelized avoided costs based on a composite proxy plant which amounted to 96$/kW/year fixed and 1.29 cent/kW.h variable.

(2) Calculated assuming 25 MW @ 75% capacity factor

(3) Calculated using 11.5% discount rate

(4) Calculated using each particpant's discount rates (ERCB: 11.5%. Southview: 12.15%. APL: 10.24%. TAU: 11%)

(5) Southview calculated levelized avoided costs based on 21 years of annual avoided costs. Based on 20 years of contract, the levelized



BOARD ESTIMATE OF AVOIDED COST FOR THE ALBERTA INTERCONNECTED SYSTEM FOR 1989—2008

There was some difference of opinion among the parties as to an appropriate assumption of plant life. The Board believes that 35 years is a reasonable life for a base-load coal plant for planning purposes and notes that this is the figure commonly used in the industry. For the gas turbine portion of the composite proxy, a useful life of 25 years and an annual depreciation rate of 4 per cent are adopted.

For the period 1995 to 2008, the foregoing assumptions were used to calculate annual fixed costs for the coal/gas proxy starting at mid-year 1995. These costs were then converted to a stream of annual cost figures which rise at the rate of inflation and reflect the value of deferring the proxy unit 1 year at a time. These annual deferred fixed costs were then added to the fixed fuel and operating and maintenance costs, resulting in total avoided fixed costs. A capacity factor of 77 per cent was used to translate these costs into a cents-per-kilowatt-hour equivalent. The total avoided costs for 1995 and thereafter were derived by adding the variable costs, operating and maintenance and fuel, to the total fixed costs. As noted previously, the fuel costs during this period are based on 90 per cent of the annual coal costs and 10 per cent of the annual gas costs. For the period prior to 1995, avoided energy costs are equivalent to the AIS marginal running costs. The Board accepts that coal mine sunk costs are not avoidable and believes the marginal energy costs as estimated by TransAlta are appropriate. The Board's estimates of the AIS avoided costs for 1989 to 2008 are shown graphically in the Figure and in Table 1, column 8.

As indicated in Table 1, the total AIS avoided costs over the entire 20-year period, as calculated by Southview, are some $106 million higher ($31 million on a present-worth basis) than that found to be the case by the Board (column 3 minus column 9). The TransAlta estimate is some $23 million ($5 million on a present-worth basis) and Alberta Power $14 million ($2 million on a present-worth basis) lower than that of the Board, respectively.

The Board notes that, if capacity payments were made to Southview starting in 1989 despite the lack of need for that capacity, the levelized avoided cost over the 20-year period would be 3.9 cents/kW·h. However, this additional cost for capacity which is not needed would result in an overstatement of avoided costs by some $22 million ($15 million on a present-worth basis).

7 PRICES AND PRINCIPLES OF PRICE DETERMINATION

7.1 Views of the Applicant

Southview stated that the Board had the authority to set prices by virtue of its application that the Board determine the basis for establishing a price and also to establish that price. In its application, Southview requested the Board adopt 5.24 cents/kW·h as

the levelized payment for a fixed 20-year contract period beginning in 1989. The applicant indicated that levelization is essential to its financing. While it recognized that such levelization puts the consumer at some risk, Southview stated that this risk is minimal because payment would be in excess of avoided costs for only the first 5 years of the contract period. Furthermore, it claimed its project would take away some risks from the consumer which are inherent in the building and operating of a generating plant by a utility. Southview stated that, for these reasons, it would be inappropriate to impose significant financial burdens on the project arising from the requirement of guarantees such as a performance bond. It also noted that financing would become a problem if the price paid to Southview were based on avoided costs calculated using the Fuel Offset Method. Southview argued that this would not lead to a bankable contract which requires that prices be determined in advance for a significant number of years, notwithstanding that the forecast of avoided costs upon which they are based could turn out to be incorrect.

Southview also expressed the view that a kilowatt of power should have the same value, regardless of source. Therefore, a discount as suggested by TransAlta and Alberta Power should not be applied to its proposal.

7.2 Views of the Interveners

Athabasca believed that the Board has the authority to approve the methodology to determine prices. It did not have a position as to whether or not the Board could actually determine prices. Athabasca did state, however, that the pricing proposal presented by Southview is fair and equitable to all electric consumers in the province. Further, consideration should be given to other factors such as socio-economic benefits, even if this implies a price greater than that determined solely on the basis of avoided cost.

TransAlta stated that section 17 of the Act gives the Board no jurisdiction to set the amount of compensation. It further suggested that any order relating to pricing should be conditional upon Board approval of a facility application. It also indicated that an order of the ERCB establishing a basis for price should be followed by approval by the Public Utilities Board (PUB) as to amount.

Despite this reservation, for illustrative purposes, TransAlta calculated prices it considered appropriate for the Southview project based on avoided costs determined by the Fuel Offset Method. TransAlta converted the avoided costs to on-peak and off-peak energy prices and on-peak capacity prices where the peak is defined as 9:00 a.m. to 9:00 p.m. weekdays, excluding statutory holidays. The levelized capacity price was calculated to be 1.42 cents/kW·h and would be paid for peak-hour production only. TransAlta considered time-differentiated pricing important in reflecting the fact that both energy and capacity have more value during peak periods.

TransAlta expressed concern over any "locking in" of assumptions regarding fuel escalation rates because such costs tend to be volatile. It proposed an annual determination of energy costs. It stated that, if the energy component is to be fixed, the contract period should be limited to 10 years to minimize the risk of overpayment or under-payment.

TransAlta also expressed concern with the levelization of prices over the contract term. With this procedure, consumers pay higher than avoided cost throughout the period and do not finally break even until the last year of the contract. TransAlta would be willing to levelize the capacity payment over a 20-year contract if there were some financial guarantee, such as a bond. Accordingly, the difference between the levelized price and true avoided cost would be repaid in the event that a producer ceased or substantially curtailed production prior to the end of the contract period.

TransAlta also calculated prices based on avoided costs using the composite proxy unit approach. TransAlta converted the avoided costs to on-peak and off-peak energy prices and on-peak capacity prices where the peak is defined as 9:00 a.m. to 9:00 p.m. weekdays, excluding statutory holidays. The levelized capacity price was calculated to be 3.43 cents/kW·h and would be paid for peak-hour production only. TransAlta added that its comments regarding fixed energy prices and a levelized capacity component made under the Fuel Offset Method would also apply to this approach.

TransAlta stated that prices based on avoided cost calculations should act as a ceiling on the price paid to Southview. It suggested a 10 per cent discount from this ceiling would be appropriate to account for the differences in the quality of service from the facility relative to the utility alternative. These differences arise from the obligation to serve which binds the utility but not Southview.

Alberta Power was of the view that section 17(5) of the Act might give the ERCB authority to establish a basis for compensation. It believed that section 17(6) appears to contemplate negotiation and, where agreement cannot be reached, the amount being determined by the PUB. Alberta Power suggested that the ERCB establish some general guidelines to enable involved parties to reach agreement through negotiation. Alberta Power further stated that, whatever the ERCB determined, it should not bind the PUB to the point where that Board was not free to use its discretion as to the amount of compensation.

Alberta Power stated that the final prices paid for power from projects such as the Southview facility, which is large enough to impact the planning of the AIS, should be determined on a case-by-case basis through negotiation. Guidelines as to a methodology by which avoided costs can be calculated could be used as a starting point for the negotiating process. It indicated that negotiation would be preferable to a specific price that is applicable to all independent power production, because it would allow for the different characteristics of each project to be considered. Alberta Power also stated that the

avoided cost estimates should be used to determine a ceiling price and the final price paid should be somewhat less in order to provide benefits to consumers. The size of the discount would be part of the negotiating process. Further, no payment for capacity should be included or paid prior to the time the capacity is required on the AIS, unless there are long-term benefits to consumers to balance the risks inherent in early payment.

Alberta Power also expressed concern over the risk to consumers from the adoption of a levelized contract. It also noted that time-differentiated prices would be desirable.

IPCAA agreed with TransAlta's view that the ERCB has no authority to establish prices. It believed that any pricing principles determined by the Board should be applied on a general basis to all future independent power projects. Also, any recommendations should be consistent with the findings of the Small Power Inquiry. IPCAA disagreed with the position taken by Alberta Power that the final price paid to an independent producer should be determined on a case-by-case basis through negotiation. Instead, it preferred a price which is pre-determined by the PUB.

Edmonton Power expressed the view that the ERCB does not have authority to set prices or establish a methodology for the establishment of price. It believed that such matters fall within the jurisdiction of the PUB. Edmonton Power believed that the ERCB can establish broad principles for a methodology regarding prices, but only as a guideline for negotiation.

The City of Calgary stated that the ERCB has no authority to establish a basis for prices; rather, such a basis should be determined by the PUB. It also took the position that consumers should not be expected to pay higher rates initially for the purpose of levelizing the revenue stream of an independent power producer. It stated that this would create intergenerational inequities.

Red Deer-Lloydminster indicated that the Board has no authority to establish price because that falls within the jurisdiction of the PUB. However, they indicated that the ERCB should comment on the methodology of the determination of costs as well as on the price proposed by Southview. They noted that pricing based on some approach other than the usual rate of return regulation would be appropriate only for generators which have been granted an exemption from utility status by the PUB. In regard to levelization of prices over the contract term, they stated that the adoption of this procedure without some adequate financial guarantee or security would, in their opinion, be an unfortunate precedent.

7.3 Views of the Board

The Board believes that it has no jurisdiction to establish prices. However, the Board considers that AIS avoided costs can be used as a

basis for compensation. The Board notes that any price exceeding AIS avoided costs would not be consistent with the economic, orderly, and efficient development of the generation of electric energy in Alberta. Nevertheless, the Board recognizes that if a contract is negotiated, the price or pricing provisions should be subject to the approval of the PUB. The Board also believes that the PUB would have to decide if exemptions from utility regulation would be appropriate.

The ERCB, in dealing with economic, orderly, and efficient development in the broad public interest, might consider local socio-economic matters but only in situations where costs of competing projects were relatively close. In this particular application, the Board considers that it would not be in the public interest to factor local socio-economic matters into cost calculations, thereby increasing the cost to be borne by utility customers.

The ERCB avoided costs shown in Table 1 were calculated without any adjustment for either time-of-day use or reliability. Although the power plant application has not been heard, the Board has assumed that Southview's plant would perform as stated in this application. Therefore, the Board has not discounted the avoided costs. The levelized avoided cost of 2.76 cents/kW·h shown in Table 1 assumes operation starts in 1989. As shown in the Figure, the avoided cost would be substantially higher if operation started in 1995 when capacity is needed on the AIS. As stated in Section 5 of this report, inclusion of transmission losses would be premature.

The Board recognizes that negotiations between the parties, and price approval by the PUB, could result in contracts different from the 20-year period assumed for avoided costs in this report. Furthermore, the Board has not considered the issue of levelization and the associated front-end risk to the consumers as it considers this to be a pricing matter and, therefore, under the jurisdiction of the PUB.

8 DECISION

Having considered all the evidence, and having regard for its responsibilities under the Hydro and Electric Energy Act,

1. the Board is prepared to approve connection of the Southview plant to the Alberta electric system via the facilities of TransAlta, subject to Southview obtaining approval of a detailed power plant application;

2. the Board is of the view that, if the price paid for compensation exceeds the AIS avoided costs, the connection of the plant would not be consistent with the economic, orderly, and efficient development of electric energy;

3. The Board has no jurisdiction to fix prices but, as a basis for compensation, AIS avoided costs should be calculated based on the principles of avoided cost determination as set out in this report.

DATED at Calgary, Alberta, on 25 March 1988.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

F. J. Mink, P.Eng.
Board Member

N. W. MacDonald

N. W. MacDonald, P.Eng.
Acting Board Member

TABLE 2 AVOIDED COST PARAMETERS

PARAMETERS	VALUES			
	SOUTHVIEW	TRANSALTA	ALBERTA POWER	ERCB
AVOIDED ENERGY 1989-1993/94 (cents/kW.h)	2.0 - 2.4	1.0 - 1.7	1.0 - 1.2	1.0 - 1.7
GENERAL INFLATION (%/annum)	5.0	4.72	4.0	4.5
REAL ESCALATION (% annum)				
o Fuel	2.0	2.0	0	2
o Labour	1.0	0	0	0
o Material	0	0	0	0
CAPITAL STRUCTURE				
o Debt	38% @ 11.8%	53% @ 9.5%	40% @ 9.75%	50% @ 9.5%
o Preferred	24% @ 9.0%	10% @ 9.0%	25% @ 7.16%	)50% @ 13.5%
o Common	38% @ 14.5%	37% @ 14.0%	35% @ 13.0%	)
o Discount Rate/ Composite Cost of Capital	12.15% nominal or 6.8% real	11.0% nominal or 6% real	10.24% nominal or 6% real	11.5% nominal or 6.7% real
INCOME TAX RATES (%)	50.52	47.5	44.0	43.8
COAL UNIT LIFE (years)	30	35	35	35
GAS UNIT LIFE (years)	-	25	-	25
LINE LOSSES (%)	2	0	0	0
POLLUTION CONTROL ON-SITE LOAD (%)	5	0	0	0

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

RANCHMEN'S RESOURCES LTD.
BATTERY/COMPRESSOR APPLICATION
PIPELINE APPLICATIONS
CYGNET FIELD

Decision D 88-3
Applications 871943, 871913, and 872057

1 APPLICATIONS AND HEARING

1.1 Applications

The Energy Resources Conservation Board (Board) received an application (Application 871943) from Ranchmen's Resources Ltd. (Ranchmen's), pursuant to sections 7.001 and 7.002 of the Oil and Gas Conservation Regulations, for approval to construct and operate an oil and gas battery facility located at Lsd 15-16-39-28 W4M (the 15-16 location). The battery facility would be for the purpose of receiving production from three oil wells and five gas wells and subsequent separation and disposition of oil, condensate, gas, and water produced from these wells. Compression facilities would be required to increase the pressure of the low-pressure solution gas stream for commingling with high-pressure gas from the gas wells. Produced gas would be transported via pipeline to nearby gas processing facilities operated by Westridge Petroleum Corporation (Westridge), while liquid hydrocarbon production would be trucked from the battery facility to a sales terminal.

The Board also received applications (Applications 871913 and 872057) from Ranchmen's, pursuant to section 2 of the Pipeline Regulations, for approval to construct and operate the pipelines required for the transmission of the oil and gas well effluent to the battery facility.

1.2 Background

The proposed site is located approximately 10 kilometres northwest of Red Deer in the valley of the Blindman River.

Ranchmen's had initially applied to the Board for approval to construct a gas processing plant as well as an oil battery at this location. A public meeting was held at the Aspelund Community Hall on 24 March 1987 at which the battery and gas plant proposal was discussed. Concerns were raised at that meeting regarding the presence of the proposed gas plant in the river valley, as well as the proliferation of small gas plants in the area. Ranchmen's subsequently reached agreement with Westridge to process the gas from the Ranchmen's battery and withdrew its application for a gas plant. However, residents in the area continued to oppose the location of the battery facility and, as a result, the Board scheduled a public hearing to consider their representations.

1.3 Interventions

Mr. Martin, a landowner with two residences located less than 1 kilometre to the east of the proposed battery site, expressed concern that noise from the facility, particularly the gas compression equipment, would have an adverse effect on these residences. Also, the facility would be in direct view from these residences, thereby marring his view of the valley.

Additionally, he believed that wildlife in the valley would leave the area because of the industrial intrusion. Mr. Martin concluded that the quality of life he had sought on this parcel of land would be adversely affected by the facility.

Mr. Symington, a resident landowner approximately 2 kilometres to the northwest of the proposed site, filed a letter of objection to the proposal on the basis of a number of matters. In particular, he was concerned about the increased risks to public safety associated with the heavy truck traffic required to transport liquid production from the site. He was also concerned about the environmental impact of the proposed facility on the river valley, particularly of a potential liquid spill in close proximity to the river. He suggested a better location could be found out of the valley. Mr. Symington did not appear at the hearing, but requested by letter that the Board consider his concerns in its decision on the application.

Ranchmen's was also made aware of concerns of other local residents regarding matters of environmental effects on the river valley and aesthetics, and the impacts of truck traffic on road quality and local agricultural traffic.

1.4 Hearing

Hearing of these applications was held in Red Deer on 26 January 1988 before N. A. Strom, P.Eng., E. J. Morin, P.Eng., and J. R. Nichol, P.Eng. The participants at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Ranchmen's Resources Ltd. (Ranchmen's) R. Neufeld	T. D. Brooker, P.Eng. V. Aarflot
Alberta Environment R. L. Grover	
Rustum Petroleums Limited (Rustum) B. Newton	
Mr. D. Martin	
Energy Resources Conservation Board staff B. B. Boyd R. J. Cox, P.Eng. T. J. Pesta, P.Eng.	

2 ISSUES

In making its decision, the Board considered the following matters:

- o resource conservation aspects of the proposed facility,
- o the proposed location of the facility, including potential alternative locations, and
- o the impacts of the facility and measures available to mitigate these impacts. The Board considered the relevant impacts to include noise, traffic, visual effects, and environmental matters.

3 DISCUSSIONS OF THE ISSUES

3.1 Resource Conservation

Ranchmen's stated that its proposed facility was needed to conserve gas currently being flared from producing oil wells. It stated that all produced hydrocarbons would be conserved by compressing both solution gas and stock tank vapours and transporting that gas by pipeline to the Westridge plant.

The alternative to the proposed central facility would be single-well batteries at each of the oil wells, with the flaring or venting of the associated gas production at each site. Individual compressors at each oil well to effect gas conservation would not be economic.

The Board recognizes that the Ranchmen's facility would enhance solution gas conservation and reduce environmental impact by eliminating solution gas flaring now occurring at the single-well oil batteries. The Board believes the proposed central oil and gas separation and compressor facility would represent a positive step in achieving economic, orderly, and environmentally-improved means of development of oil and gas reserves in the area under consideration.

3.2 Facility Location

Ranchmen's stated that the proposed site is the best possible location since it is centrally located with respect to the wells that would produce to the battery facility and would minimize the number of pipelines and river crossings. It also stated that the location in the Blindman River valley would provide gravitational flow of liquids from the wells toward the battery facility, thereby preventing the build-up and flow of intermittent liquid slugs that would tend to cause upsets and unstable operation if the facility were placed out of the valley.

Ranchmen's added that the proposed location would minimize the impact on the surrounding community by being set well back from the county road and out of view from most residents and users of that road.

With respect to suggestions of alternative locations out of the valley, Ranchmen's stated that such a location would require the installation of an expensive liquid collection system to remove liquid slugs upstream of the battery facility. It further explained that while such equipment would be effective in removing the liquid itself, it would not remove the problems associated with pressure fluctuations caused by each liquid slug. To Ranchmen's knowledge there is no way to handle or regulate these pressure fluctuations. Ranchmen's stated that the effect of these pressure fluctuations would require them to by-pass the compressor and flare gas whenever a slug reached the battery facility.

The Board agrees that the proposed 15-16 location is centrally located with respect to the wells that would produce to the battery facility. It also agrees that a location in the valley, because it would avoid liquid slug effects, would minimize the possibility of operational upsets and the need to flare gas or liquids at the battery.

3.3 Impacts

3.3.1 Noise

Mr. Martin expressed concern that the noise from the facility would be projected upwards and directed towards his residences and that the noise would be louder because the valley acts as an amplifier.
Mr. Martin also expressed concern over the noise presently generated by the flaring of gas at the single-well batteries. He stated that the noise from this flaring is noticeable on his property.

Ranchmen's stated that it had hired an acoustical consultant to conduct a baseline ambient noise survey at the residences on Mr. Martin's land. To minimize noise from the facility, Ranchmen's intends to use hospital-type mufflers on the compressor engine, experiment with the positioning of exhausts and cooler fans, install cooler fan shrouds, and insulate the compressor building. With respect to proposed amendments to ERCB noise guidelines, Ranchmen's had not been advised by its noise consultant as to whether these guidelines could be met, and suggested that actual noise levels could not be determined until the facility was in operation. It indicated, however, that it would work with both Mr. Martin and the ERCB, through its acoustical consultant, to establish an acceptable noise suppression program. Results would be verified by a noise impact study conducted after the commencement of operations at the facility.

The Board recognizes the potential noise impact, particularly at the residences on Mr. Martin's land. It acknowledges the steps to be taken by Ranchmen's to mitigate impacts by hiring an acoustical consultant and implementing noise suppression techniques at the design stage. The Board believes that these preparations will be beneficial. However, it also agrees that actual noise levels cannot be determined until the facility is operational. In that regard, the Board acknowledges Ranchmen's intentions to conduct a noise level survey during operation and to implement further mitigative measures as necessary.

The Board is satisifed that, with these and other reasonable noise suppression measures as may be necessary, a satisfactory noise level will be achieved.

3.3.2 Visual Effects

With respect to concerns over impacts on the aesthetics of the area, Ranchmen's stated that a row of mature trees will be planted along the eastern edge of the facility to reduce the visual impact from Mr. Martin's residences and to users of the county road to the east of the facility. Ranchmen's further stated that mature trees will also be planted on Mr. Martin's property to further reduce the visual impact from Mr. Martin's residences. It added that earth-tone colours will be used on the facility buildings and equipment.

Ranchmen's also stated that there will be no flaring of gas under normal operating conditions and that the battery facility will eliminate the flaring of gas at the single-well batteries in the area.

Mr. Martin expressed concern that the facility will degrade the aesthetic value of the river valley and his property. He acknowledged that Ranchmen's was committed to the planting of mature trees around the facility and the property in front of his residences to obscure the view of the facility.

While some impact is inevitable, the Board believes that the measures proposed by Ranchmen's will reduce the visual impacts from the facility to an acceptable level.

3.3.3 Environmental

Ranchmen's stated that it had designed its gathering system to minimize the amount of surface disturbance, and to require only one river crossing. By locating the facility in the river valley it would minimize the potential dangers of having to deal with liquid slugging and consequently reduce the potential for on-site spills. Ranchmen's indicated that not only would the oil, condensate, and produced water tanks be diked but a second dike would be constructed around the perimeter of the facility site to minimize the potential for off-site runoff from any liquid spills as well as direct natural runoff around the facility.

At the hearing, Ranchmen's also responded to questions from Alberta Environment pertaining to land reclamation for the battery facility site and the pipelines. The main concern was conservation of topsoil during winter construction. Ranchmen's stated that it would apply appropriate winter construction methods and would ensure that proper reclamation was carried out.

The Board recognizes that some impact on the environment is inevitable, particularly with respect to surface disturbance. However, the Board believes that the procedures described by Ranchmen's will ensure that the pipelines and battery facility are constructed and operated with minimal and acceptable environmental impacts.

3.3.4 Traffic

Ranchmen's stated that it believed that the roads in the area can easily handle the one or two tanker trucks per day it would require. It proposes to truck out hydrocarbon liquid production by taking it north on the county road to what is commonly referred to as the Aspelund Highway. Ranchmen's stated that the county road going north from its facility has been upgraded and that the Aspelund Highway is a secondary paved county road. It believes that these roads are capable of handling the traffic to and from its facility. Ranchmen's further added that this was confirmed by a representative of the County of Lacombe at the public meeting on 24 March 1987. Ranchmen's stated that it would direct the truckers to use appropriate caution and to adhere to the local traffic laws.

Ranchmen's added that the proposed battery facility would also eliminate the trucking of liquids from the single-well batteries in the area.

Ranchmen's stated that although pipelining would be its preferred method of transporting oil and condensate from its facility to a market terminal, that is not economically feasible at current production rates.

The Board notes that the trucking of liquids would be confined to the Ranchmen's facility at Lsd 15-16-39-28 W4M instead of a number of single-well batteries. It does not believe that the volume of truck

traffic that would be generated by the Ranchmen's facility is of sufficient magnitude to have an adverse impact on the local area traffic or roads.

However, the Board believes it would be appropriate, as indicated by Ranchmen's, to make truckers travelling to and from the facility aware of the concerns of local residents and direct them to use appropriate caution.

3.3.5 Wildlife

Ranchmen's acknowledged the presence of wildlife in the area and has agreed to lock the gate to the access road to avoid unauthorized intrusion.

The Board recognizes that there will be impacts on the wildlife. However, the Board believes that the impacts will be minimal with access closure and other measures to reduce noise from the facility.

4 DECISION

The Board is satisfied that the proposed facility is required, that it would meet all of the Board's requirements for battery and compressor facilities, and that there are valid technical reasons for the proposed location. The Board is further satisfied that Ranchmen's has committed to reasonable efforts to mitigate noise impacts, and that a noise suppression program can be designed to achieve noise levels acceptable to the Board. With respect to visual impacts, the Board believes that these can be largely resolved through Ranchmen's proposed landscaping program.

Accordingly, as stated at the 26 January 1988 public hearing in Red Deer, the Board has approved the applications for the battery facility and associated pipelines. The Board expects Ranchmen's to continue to liaise with Mr. Martin and nearby residents to ensure minimal impact from its operations, and to advise Board staff of the results of the noise study conducted after commencement of operations.

DATED at Calgary, Alberta, on 16 March 1988.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

E. J. Morin, P.Eng.
Board Member

J. R. Nichol, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

BONANZA OIL & GAS LTD.
APPLICATION FOR A WELL LICENCE
JOFFRE FIELD

Decision D 88-4
Application 871928

1 INTRODUCTION

1.1 Application

Bonanza Oil & Gas Ltd. (Bonanza) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a licence to drill a well from a surface location in legal subdivision 11 of section 12, township 38, range 27, west of the 4th meridian, to a projected bottom-hole location in legal subdivision 13 of section 12, township 38, range 27, west of the 4th meridian. The proposed well, to be known as BONANZA ET AL JOFFRE 13-12-38-27 (the well), would be for the purpose of obtaining oil production from the Leduc Formation (Leduc).

1.2 Interventions

Interventions to the application were received by the Energy Resources Conservation Board (the Board) from landowners and concerned persons in the vicinity of the proposed well. Those who appeared to speak to their interventions are identified in the following table. Generally, the interventions did not take issue with the technical merits of drilling the well but rather the potential hydrogen sulphide (H_2S) release rate in the event of a blowout, and the adequacy of the Emergency Response Plan (ERP) and associated Emergency Planning Zone (EPZ).

Two submissions were filed by individuals in support of the application.

1.3 Hearing

A public hearing of the application commenced on 8 February 1988 in Red Deer, Alberta, before a division of the Board comprised of C. J. Goodman, P.Eng., E. J. Morin, P.Eng., and J. P. Prince, Ph.D.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Bonanza Oil & Gas Ltd. (Bonanza) J. D. Rooke, Q.C.	D. S. Belczewski, P.Eng. C. G. Guza, P.Geol. L. R. Lipsett, P.Eng. H. Spence W. T. Wilson, P.Eng.
Concerned Citizens of Balmoral and Rosedale Acres Community Association (Concerned Citizens) L. S. Kanee	P. M. Dranchuk, P.Eng. D. Cawthorn R. D. Rowe, P.Eng. C. W. Wanless G. D. Williams, Ph.D.Geol.
Robert Northey and John Spencely R. Northey	R. Northey B. Spencely
Don F. Bower	D. F. Bower
Energy Resources Conservation Board staff C.J.C. Page D. K. Eresman, C.E.T. M. S. Craig R. A. Gowan, R.E.T. N. F. Lord, C.E.T. L. A. Whittaker	

1.4 Background

The proposed well would be located approximately 1.5 kilometres (km) east of the City of Red Deer (Red Deer), Alberta (see attached Figure).

The primary geological zone of interest is the Leduc, which in the area of application is typically oil bearing with sour gas in solution and possibly an associated gas cap. Bonanza interpreted the geological structure to be a pinnacle reef build-up located off the main Bashaw reef complex. The applicant said it anticipates encountering H_2S concentrations up to a maximum of 14.75 per cent, with the reservoir having a potential maximum release rate of H_2S gas of 0.214 cubic metres per second (m^3/s). Based on that potential release rate and the proximity of the well to residential areas, the Board has classed the well as critical.

1.5 Preliminary Matters

At the start of the hearing, the Concerned Citizens requested that the hearing be adjourned and consideration of the application by the Board be deferred until completion of the Concord Study into Uncontrolled Releases of Sour Gas[1]. They contended that the application should be assessed in accordance with that study's findings to ensure that it was considered using state-of-the-art models and the most current information available. It was their submission that this study was relevant to all wells in close proximity to major urban centres.

Bonanza submitted that it was premature for the Board to consider such a request and that it would be more appropriate to hear the application and evidence and then decide if a decision respecting the application could be made or if it was appropriate to defer consideration until after completion of the study.

The Board, after hearing arguments from both parties respecting this matter, decided that in order to determine the relevance of Concord material to the application, it needed to hear more evidence, particularly that related to H_2S release rates and associated EPZs. The Board then proceeded to hear the application, evidence, and submissions of the interveners.

2 ISSUES

The Board considers the issues with respect to the application to be

- the purpose and location of the well,
- the drilling of the well,
- the production of the well,
- the potential H_2S release rate,
- appropriateness of the ERP,
- submissions in support of the application, and
- the request for deferral.

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1 Concord Scientific Corporation was commissioned in 1986 by the Board to do a hazard and risk assessment for uncontrolled releases of sour gas such as well blowouts or pipeline ruptures. Phase I of that study has been completed and was released to the public in June 1987. It includes a mathematical model called GASCON which estimates gas concentrations resulting from a release of toxic gas such as H_2S. Phase II of the study, which is to provide an assessment of risk, has not yet been released, pending completion of a field measurement program to evaluate the GASCON model.

3 PURPOSE AND LOCATION OF THE WELL

3.1 Views of the Applicant

Bonanza submitted that it holds a valid mineral lease and the purpose of the well is to recover oil and gas reserves that it believes underlie the northwest quarter of section 12-38-27 W4M. It stated that it had already spent considerable funds in evaluating and developing this project and it wished to recover that investment. It submitted that it was important that these potential reserves be evaluated prior to the eastward expansion of Red Deer which could preclude the development of the reserves altogether.

Bonanza stated that the bottom-hole location was geologically optimum based on seismic interpretations. It proposed to drill the well directionally from a surface location in Lsd 11-12-38-27 W4M to maintain a 1.5-km separation distance from the boundary of Red Deer. Bonanza stated that it would be reluctant to move the surface location a greater distance as this would increase the distance and angle of directional drilling, add considerable cost, and potentially increase the risks associated with drilling and producing the well.

3.2 Views of the Interveners

The interveners did not take issue with the applicant's purpose for the well or its choice of the proposed bottom-hole location. They did submit, however, that the proposed surface location of the well is too close to Red Deer and the adjoining communities of Balmoral and Rosedale. The close proximity of the well to residential areas raised concerns regarding noise, odours, air quality, water wells, safety, and in general, quality of life in the event of a blowout during drilling or during production should the well prove successful.

3.3 Views of the Board

The Board recognizes Bonanza's wish to recover monies it has already expended in developing a potential hydrocarbon reserve for which it holds a valid mineral lease. The Board further recognizes that a successful well would allow Bonanza to recover its costs and earn a profit. A successful well would also benefit the Province as a whole through royalty payments.

An unsuccessful well would be useful in directing exploration to other areas and would contribute to certainty in planning future surface development in the area.

Recognizing the benefits that may flow from the drilling of the well, the Board believes that the objectives in drilling the well are sound and approval of the application would be appropriate provided the impacts are not so great as to preclude the drilling of the well.

Given the constraints of directional drilling, the Board believes that further limited movement of the surface location would not alleviate the concerns expressed by the interveners. Therefore the Board concludes that the proposed surface location is appropriate.

4 DRILLING OF THE WELL

4.1 Views of the Applicant

In recognition of the well's proximity to Red Deer and the concerns raised by area residents, Bonanza submitted that it had developed a highly detailed and conservative drilling plan. Bonanza stated that criteria established by the Blowout Prevention Review Committee under the direction of the Board would be met or exceeded in all respects. Bonanza submitted that all drilling and contingency equipment and materials had been designed to follow this conservative philosophy. Therefore, the proposed drilling operations, mud systems, drill pipe, blowout prevention stack, choke manifold, and mud volume measurement systems had all been designed with the critical status of the proposed well in mind. Bonanza submitted that the expected downhole conditions, in conjunction with the conservative well design, would make the chances of any well control problems extremely remote. Bonanza did, however, propose to run intermediate casing to ensure downhole formation stability and enhance well control by providing for the ability to completely shut in the well if a problem occurred. Further, rig crew training and experience and rig inspection standards would ensure Bonanza's ability to competently and safely proceed with the drilling of the well. Because of these precautions, Bonanza believed the drilling of the well would not represent any hazard or result in any noticeable impact on persons in the surrounding area.

In response to questioning, Bonanza stated that having regard for the flow potential from the Nisku Formation (Nisku), safety considerations, and the need to equip the well for efficient production, the optimum setting depth for the intermediate casing was above the Nisku rather than above the Leduc as applied for.

Bonanza recognized the concerns over possible damage to water wells in the area because of the proposed drilling operations and committed to perform baseline measurements of water quality and quantity so that any subsequent damage could be detected.

4.2 Views of the Interveners

While not specifically arguing the technical merits of the proposed drilling plan, the interveners submitted that, to protect area residents, the most rigorous and safest procedures should be imposed on the drilling of the well. They submitted that even though the undertakings of Bonanza, such as the testing of water wells, had alleviated some of their

concerns, the drilling of the well would always present an element of risk.

4.3 Views of the Board

The proposed drilling plan has been reviewed and, based on technical considerations, is satisfactory. The Board, however, wishes to affirm that it does not consider the measures proposed by Bonanza to be excessive. The Board expects that any operator proposing to drill a well classed as critical would consider measures such as those proposed by Bonanza to be standard drilling procedures. This is particularly true for wells in close proximity to urban developments.

With respect to the setting depth of the intermediate casing, the Board recognizes that the well is most likely to find no hydrocarbon in the Nisku and, if successful, oil rather than natural gas in the Leduc. However, the risks and potential consequences associated with drilling through the Nisku without intermediate casing in place, if hydrocarbons are present, are significant. On the other hand, the risks and consequences are increased only marginally if both the Nisku and Leduc are drilled without a liner, but below the intermediate casing, even if hydrocarbons are present in the Nisku. The Board therefore concludes that the intermediate casing should be run and cemented in place immediately above the Nisku.

5 PRODUCTION OF THE WELL

5.1 Views of the Applicant

Should the well prove productive, Bonanza believes its testing and permanent production operations would have minimal impact on the surrounding area. Bonanza proposed a reduced test period of approximately 2 to 7 days. Facilities would include a three-phase separator, flare, and, if artificial lift is required, a pumpjack which would be electrically driven. Once the well was tested, the product would be pipelined to an Esso facility some distance from the surface location of the well. This would ensure that production would be through a closed system and therefore there will be no impact on the surrounding area.

5.2 Views of the Interveners

The interveners submitted that the existence of permanent production facilities would always be a source of concern. They contended that risks must be considered from the perspective that the east portion of Red Deer is one of the fastest growing areas of the city and encroachment of residential communities upon the well site is inevitable. Therefore the most rigorous constraints should be placed on any production operations.

5.3 Views of the Board

The Board notes that, should the well be approved, any production test and subsequent permanent production facility would be the subject of future applications to the Board. The Board would expect that Bonanza would design the production operation with a concern for integration of resource development and nearby urbanization. The Board believes that a reduced test duration, such as that proposed by Bonanza, is appropriate. Further, the applicant should provide very close surveillance of operations during the testing to ensure immediate response in case of equipment or operational failure.

Respecting permanent production facilities, since these could be the source of problems to nearby residents over an extended period of time, the Board would expect Bonanza to consider the following:

- Equipping the well with high and low pressure shut-down devices.
- Equipping the well, if pumping, with electric drive and a blowout prevention device to shut off flow from the well in the event of a rod failure.
- Limiting lease equipment to that essential for the operation of the well. Permanent flaring facilities at the well site should be avoided.
- Properly fencing the well, including a locked gate. In addition to restricting unauthorized access to the site, the fence should be designed such that it would reduce the visual impact of the facility.
- Maintaining good housekeeping practices and regular painting.
- Erecting a sign, in a prominent place, giving the company name and 24-hour telephone numbers to contact.
- Prohibiting trucking of oil and salt water except in special circumstances.
- Electrifying the well in accordance with the area electrical system, including underground wiring if such is common in the area.

The Board notes that the applicant committed to enclosing the wellhead even if pumping facilities are required and to installing sensors within the enclosure that would activate an emergency shut-down valve in the event of even minor concentrations of H_2S. The Board also notes the applicant's commitment to transport any produced hydrocarbons through a pipeline, thereby ensuring a closed system that would minimize activity, odours, and noise.

The Board also believes that the operator should not consider these to be additional measures nor the costs associated with such steps as additional costs, but rather the normal measures and the costs associated with producing a potentially sour well in a highly sensitive area.

Given the measures described, the Board believes that the proposed well could be produced with a minimal impact on area residents.

6 POTENTIAL H_2S RELEASE RATE

6.1 Views of the Applicant

Bonanza stated that it interpreted seismic survey data to indicate a geological structural high in both the Nisku and Leduc. The applicant anticipated the Devonian Leduc to be the primary objective, with the proposed target location situated in a small pinnacle reef which would be adjacent to, but separate from, the main Wimborne-Bashaw reef trend. It expects the reef to have an areal extent of approximately 65 hectares with a vertical relief of 200 metres; however, most of this thickness is expected to contain an active water aquifer. Bonanza believes the seismic character and geological setting of this anomaly indicates that the Leduc is an oil-prone reservoir at this location and is analogous to a separate pinnacle discovered 1.4 km from the proposed well in Lsd 2-11-38-27 W4M. The applicant also cited several Leduc pools discovered in the vicinity of the area of application, all of which are traps for a light gravity crude oil and which did not display a significant observed gas cap upon discovery. Bonanza was aware, however, that many Leduc pools in the large peripheral area contained significant gas caps.

Bonanza had also prepared for the possibility of encountering hydrocarbon potential from the Nisku; however, it noted that no significant porosity or pay was found in the Nisku in the 2-11 analogue well and similarly, Nisku porosity or pay is not expected in the proposed 13-12 wellbore since the location is off the edge of the main reef mass.

Nonetheless, due to the possible presence of H_2S in the Nisku and Leduc in the general area, and as a prudent operator, Bonanza proposed to drill the well in anticipation of encountering H_2S. An estimated concentration of 12.90 per cent H_2S for the Nisku and 14.75 per cent H_2S for the Leduc was established. These estimated concentrations were obtained from the analysis of gas wells located in Lsd 10-36-38-27 W4M. These values and corresponding release rates of 0.256 m^3/s and 0.214 m^3/s for the Nisku and Leduc, respectively, were then used in designing the drilling program, production operations, and the ERP.

6.2 Views of the Interveners

Expert witnesses for the Concerned Citizens agreed that the applicant's data, used for calculating the maximum H_2S release rate potential for the Nisku, was as good as was available. The interveners contended, however,

that for the Leduc it was more reasonable to take into account the difference in pay thickness between the 2-11 analogue well and that anticipated at the proposed location. The interveners analysed available drill stem test data using modifications to flow rate pressure drawdown data and geometry as well as a second method using a Horner analysis combined with steady state flow theory. While not disputing the concentration of H_2S that could be encountered in the Leduc, the interveners arrived at an estimated release rate value of between 2.159 m^3/s and 2.362 m^3/s for the Leduc.

Because the H_2S release rate estimated by the interveners' expert witnesses was an order of magnitude greater than that submitted by the applicant, the interveners believed that the protection offered to the residents in the vicinity of the proposed well was inadequate and that it would be appropriate for Bonanza to anticipate and plan for the worst possible scenario.

6.3 Views of the Board

The Board finds the geological scenario as interpreted by Bonanza to be reasonable and accepts that only oil may be encountered in the proposed well. The Board is of the view, however, that for planning purposes it is appropriate for the applicant to anticipate encountering oil with some level of associated gas cap. The Board believes the estimated release rate used by Bonanza may be low if an associated gas cap is encountered, thus increasing the potential for much higher flow rates. The release rates presented at the hearing, by the applicant and interveners, span a very large range and the adoption of any particular rate as a basis for the drilling plan and emergency planning would have an uncertain technical basis. However, the Board agrees with the applicant that the proposed well would not likely have a release rate as high as that estimated by the interveners. The interveners' estimated maximum release rate of between 2.159 m^3/s and 2.362 m^3/s is a theoretical construct that, in the opinion of the Board, does not adequately reflect information available from other wells in the area. The Board does not accept it as a realistic maximum for planning purposes. Nonetheless, the uncertainties involved indicate that the release rate might realistically fall in a range of 0.214 m^3/s to perhaps 1.2 m^3/s. The upper level of this range is possible but unlikely, given the experience of other wells in the area. Until proof of actual reservoir conditions and flow rates is obtained, Bonanza will have to acknowledge this significant range of uncertainty in all aspects of its planning.

7 APPROPRIATENESS OF THE EMERGENCY RESPONSE PLAN

7.1 Views of the Applicant

Bonanza stated that, although the calculated EPZ based on the maximum release rate of 0.256 m^3/s is less than 1 km, it established a 1.5-km EPZ

for drilling of the 13-12 well because it felt that it was prudent that people immediately adjacent to Red Deer and the community of Balmoral be included in the plan. It also felt this distance to be the most manageable distance for evacuation in the event of an emergency. Although Bonanza does not believe it is necessary, it would, if required by the Board, include contacts for the Rosedale, Balmoral, and any other community the interveners think necessary, in their communications plan so that these communities can be kept informed of events at the well during drilling. Bonanza contended that it has a carefully prepared conservative ERP which incorporates extensive air quality monitoring and stringent ignition criteria and that the ERP would protect residents in the event of any emergency, regardless of the actual release rate.

7.2 Views of the Interveners

In general, the Concerned Citizens thought that the proposed critical sour well is too close to populated areas. Because the potential H_2S release rate estimated by its expert witness was an order of magnitude greater than that estimated by the applicant, the Concerned Citizens believed that the protection offered to the residents would not be adequate and it would be appropriate for Bonanza to plan for the worst possible scenario. It suggested that if the release rate and emergency planning zone proposed by the applicant were to be accepted by the Board, Bonanza should be required to notify the residents of Balmoral and Rosedale in the event of an emergency at the well. Bonanza should also be required to immediately ignite any uncontrolled release from the well.

The Concerned Citizens recommended that a berm be constructed around the well to deflect any releases, in the event of a blowout, in a vertical direction and improve dispersion. In response to questioning, it was acknowledged that the interveners had not considered how the berm would be constructed, or even if one was practical.

7.3 Views of the Board

The Board recognizes the well's proximity to Red Deer and adjacent residential communities and the uncertainty of actual release rates that may be encountered. If it were to approve the application, the Board would require immediate ignition of the well in the event of an uncontrolled release of H_2S. Given stringent ignition criteria, the Board believes a 1.5-km EPZ to be safe and reasonable and one which is practical from an operational perspective. In addition, a requirement for immediate ignition negates the need for a berm around the well as the heat of combustion would provide a strong vertical component to any release and would ensure rapid dispersion.

The Board notes that the ERP is a matter yet to be finalized as the plan must be formally approved by the Board prior to the well licence being issued. The Board would require that representatives of the Balmoral and

Rosedale subdivisions be included in Bonanza's communication plans and that they be kept fully informed of drilling progress and of any emergencies.

8 SUBMISSIONS IN SUPPORT OF THE APPLICATION

Those parties filing in support of the application stated that they believed Bonanza has taken appropriate measures to ensure the safety of residents in the area. They submitted that they had canvassed numerous residents who indicated they also were supporters of the application. After reviewing the application and having considered the regulations and guidelines established by the Board, they believed the well could be drilled safely and have little effect upon the residents. They did request, however, that all safety measures, drilling procedures, and guidelines as set out by the Board be strictly enforced and that the Board make available a member of its staff to address any concerns or questions from citizens during the drilling of the well.

The Board wishes to assure all parties that a detailed review of the application and the strict enforcement of regulations pertaining to a well such as that proposed by Bonanza, are viewed by the Board as having the utmost importance. The Board wishes to also confirm that members of its field staff in Red Deer, and staff situated at its offices in other locations in the Province, as well as Calgary, are available at all times to answer queries or concerns respecting the Board's regulations, guidelines, and practices.

9 REQUEST FOR DEFERRAL

9.1 Views of the Applicant

Bonanza submitted that it believed the request for deferral, pending the completion of the Concord Study, was not appropriate as the study did not relate to well applications in general but rather to the specific Canadian Occidental well licence applications. Bonanza submitted that the Canadian Occidental applications were materially different from its application currently before the Board in several significant ways. Two primary differences are that Canadian Occidental proposes to drill gas wells to produce from the Crossfield and/or Wabamum Formations whereas Bonanza anticipates an oil well completed in the Leduc. Moreover, such parameters as reservoir pressures, wellhead absolute open flow pressures, H_2S concentration, maximum H_2S release rates, facility levels, and EPZs were expected to be significantly higher in the Canadian Occidental wells. As a result, concerns related to the Bonanza oil well are significantly less than those applicable to the Canadian Occidental sour gas wells.

Notwithstanding these differences, Bonanza stated that because of its conservative approach to the planning of the well and the mitigative measures it was required and willing to implement, any deferral of the

application would not result in any significant changes to its approach to the well.

Bonanza noted that subsequent to the submission of the Canadian Occidental applications to the Board for consideration, the Board had approved several sour gas well applications in various locations throughout the Province.

9.2 Views of the Interveners

The Concerned Citizens submitted that until Phase II of the Concord Study had been completed and properly assessed, Bonanza's well licence application should not be approved. They believed that they deserved to have the application assessed using state-of-the-art models and the most current technical information. They stated that Phase II of the Concord Study was to answer the question "what are the chances of lethal levels of toxic gas reaching the populated area around a sour gas facility?" Until this question is answered, they submitted that a sour gas facility should not be approved in close proximity to a populated area.

Witnesses for the Concerned Citizens had investigated the parameters and data used in determining the EPZ and believed that Bonanza had not arrived at the most conservative estimate. In particular, variances in assumptions of windspeeds and release rates would give rise to an EPZ which encompassed a substantial portion of Red Deer and that was believed by the Concerned Citizens to be more appropriate than the EPZ proposed by Bonanza.

Given these variances, the Concerned Citizens felt that their concerns were deserving of the same consideration which the concerns of the residents in the northeast Calgary communities have received. Accordingly, the Concerned Citizens submitted that consideration of Bonanza's application should be adjourned pending the outcome of the Concord Study.

9.3 Views of the Board

The Board acknowledges that there are differences between the Bonanza well and the wells proposed by Canadian Occidental. The differences would likely be even more significant if the wells go on production, since the Bonanza well would likely produce oil whereas the Canadian Occidental wells would be expected to produce gas. There is, however, some overlap of the range in which the possible H_2S release rates for the wells may fall, and the most likely release rates for the wells as stated in the applications are of the same order of magnitude. Therefore, the Board does not believe that the differences alone are sufficient grounds to dismiss the request for a deferral as suggested by the applicant.

The Board's current policy relating to emergency planning was established with consideration for many factors, including results from several

existing atmospheric dispersion models. Although these models represent an older technology than that being developed by Concord, many of the same principles were used. Preliminary indications are that both the Concord and older model predictions are in the same order of magnitude. The Board notes that further progress on the application of the Concord Study has been delayed pending a field measurement program to evaluate the atmospheric dispersion model under certain conditions, particularly low wind speeds. The Board also notes that available evidence from the field, in particular from the incident at Lodgepole, indicates that the predictions of the existing models are conservative.

The Board recognizes technological and scientific advances are ongoing and these will, on occasion, lead to re-evaluation of policies in specific areas. But even when special studies promise to add to the Board's general understanding of relevant phenomena (as is the case with the atmospheric dispersion models under development by Concord), there may be sufficient evidence available to enable the Board to approve or deny a specific application.

In the case at hand, because predictions from the Board's current models of atmospheric dispersion are similar to those of the GASCON model that may be tested later this year, and because available field evidence suggests that, if the models err they err on the conservative side, the Board believes that a decision can be made on the available evidence, particularly if the decision includes appropriate conditions relevant to this specific application.

10 CONCLUSION

Having reviewed the evidence, the Board concludes that the drilling and production of the well can proceed in a safe manner.

11 DECISION

The Board is therefore prepared to approve Application 871928 and issue a well licence, subject to the following conditions:

1. Intermediate casing is to be set and cemented above the Nisku.

2. The Emergency Response Plan is to be revised to include the following:

    (a) Communications provisions in the plan to ensure that the communities of Balmoral and Rosedale are kept fully informed during the drilling of the well, at the first indication of any emergency, and throughout any emergency.

    (b) Ignition criteria to provide for immediate ignition of the well in case of an uncontrolled flow. Uncontrolled flow for this purpose is defined as any unrestricted flow at surface that

cannot be shut off at the operator's discretion or safely flared.

3. Bonanza shall, on request, test any water well within a 2.5-km radius of the well, for quantity and quality of the water, before and after the drilling of the well.

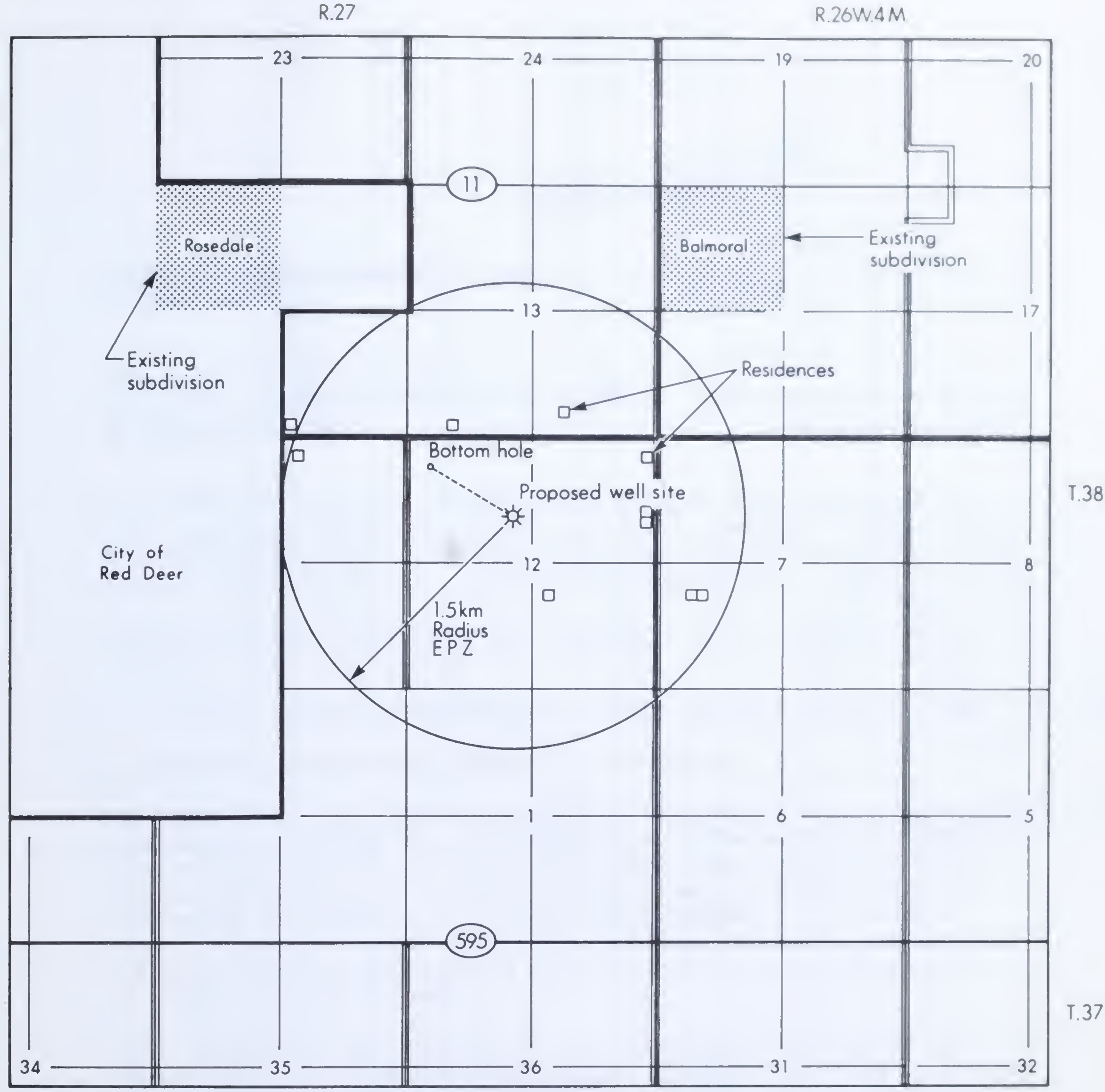
DATED at Calgary, Alberta on 11 May 1988.

ENERGY RESOURCES CONSERVATION BOARD

E. J. Morin, P.Eng.
Board Member

J. P. Prince, Ph.D.
Board Member

C. J. Goodman retired prior to the completion of this report. He agreed in principle with the findings, conclusions, and decision. Since he will not see the Emergency Response Plan, his agreement was conditional on any uncontrolled sour gas release being ignited without delay or question.



APPLICATION FOR A WELL LICENCE

Application No. 871928

BONANZA ET AL JOFFRE 13-12-38-27

Surface Location LSD 11-12-38-27W.4M.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY AEC PIPELINES
FOR A PUMP STATION AND RELATED FACILITIES
IN THE LA COREY AREA

Interim Decision D 88-5
Application 871983

At a public hearing held in Bonnyville, Alberta, on 13 and 14 April 1988, the Energy Resources Conservation Board considered an application by AEC Pipelines (AEC) to construct an 11 190-kilowatt pump station and related facilities near its existing La Corey station.

The Board believes that the evidence given at the hearing can be reasonably separated into two matters:

1. concerns regarding the existing La Corey terminal operation, and

2. matters respecting the proposed new facility.

The Board found the evidence presented at the hearing related mainly to environmental concerns about the operations at the existing La Corey terminal facilities and believes that the concerns identified will not be exacerbated by the new facility. There was no evidence presented challenging the need for the proposed pump station or its technical merits. Given the expanding activity of bitumen producing projects in the area, the Board is satisfied that the facilities are needed and are technically satisfactory.

Having regard for the evidence and for the urgency expressed by AEC respecting its construction and operation schedule, the Board is issuing this interim decision dealing with the proposed new facility and will consider matters related to the existing terminal in a subsequent report.

The Board is satisfied that the new facility meets the requirements set out in the Pipeline Act and Pipeline Regulations and is prepared to issue the appropriate permit in accordance with Part 4 of the Pipeline Act. The Board notes that in response to concerns expressed by the interveners, AEC has committed to meet the ERCB noise guidelines at its existing and proposed facilities. The Board expects that AEC will

conduct suitable tests following completion of the facilities to verify conformance to the guidelines.

The interveners requested that any permit to construct the proposed pump station and related facilities should be subject to a number of conditions. The following outlines the Board's views on these items and identifies the conditions that would be imposed on the facilities in the permit.

1. There should not be an outlet for the fluids contained in the dikes around the tanks.

   The Board notes that fluids released from within the dike area must meet specific provincial standards for surface runoff. The Board expects AEC to closely monitor the contained fluids for conformance to these standards. It does not believe that a special condition is required.

2. Alarm systems should be installed at the new facility.

   The Board recognizes the concerns of the residents, but notes that the 24-hour access telephone number provided by AEC can be used to report problems to AEC. The Board also notes that the station operations will be monitored by telemetry at a central control site and that there is an operator stationed locally to take appropriate actions if required. The Board concludes that a special alarm would not be required.

3. Construction activity should not be permitted between 11:00 p.m. and 6:00 a.m.

   The Board understands the concerns of the residents to limit construction to some extent. The Board notes that AEC intends to utilize normal daylight construction shifts which would meet the request of local residents. The Board expects AEC to notify the Board and local residents in the event special circumstances arise which would warrant construction occurring during the 11:00 p.m. to 6:00 a.m. time period.

4. An H_2S monitor should be placed in the new facility.

   The Board notes that the new facility is a closed system and that the expected emission and concentrations of H_2S at the location are negligible. The Board, therefore, believes that a requirement for an H_2S monitor at the site is not necessary.

5. Residents should be notified of further expansion to the new facility.
   The Board believes that residents should be advised well in advance of any new developments at the site and will condition the permit to ensure that residents are notified by AEC of any future expansion to the facility.

Dated at Calgary, Alberta, on 26 April 1988.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Board Member

J. D. Dilay, P.Eng.
Acting Board Member

K. G. Sharp, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY AEC PIPELINES
FOR A PUMP STATION AND RELATED FACILITIES
IN THE LA COREY AREA

Decision D 88-5
Application 871983

1 INTRODUCTION

1.1 Application

AEC Pipelines (AEC) applied, pursuant to Part 4 of the Pipeline Act, for a permit to construct an 11 190-kilowatt pump station and related facilities along its Cold Lake to Edmonton pipeline system at legal subdivision 14 of section 30, township 63, range 5, west of the 4th meridian (the La Corey terminal).

1.2 Background

AEC held a public meeting at La Corey on 17 November 1987 to discuss its proposed facility. A number of concerns were raised at the meeting including odour from the present truck terminal, increasing truck traffic, and noise. Following receipt of AEC's application for the proposed terminal, the Board received letters of objection from local residents expressing concerns about odours from the existing facility, noise, truck traffic, depreciation of land values, and other possible impacts of further expansion.

Because of the concerns expressed by the residents, the Board agreed that the design and operation of the existing La Corey oil terminal and trucking facility would be addressed at the hearing in addition to the application for the new pump station.

1.3 Hearing

A public hearing of the application was held in Bonnyville on 13 and 14 April 1988, with F. J. Mink, P.Eng., J. D. Dilay, P.Eng., and K. G. Sharp, P.Eng., sitting. Participants at the hearing are listed in the attached table. The Board panel and concerned parties visited the existing truck terminal during the course of the hearing.

The attached figure shows the existing and applied-for facilities, the location of the nearby residences, including those of the interveners, and certain major features of the area.

2 ISSUES

In considering the application, interventions, and evidence provided at the hearing, the Board sees that there are two categories of issues. These are:

- o matters respecting the proposed new facility, and
- o concerns regarding the existing La Corey terminal.

The Board issued Interim Decision D 88-5 on 26 April 1988 addressing matters related to the new facility. A copy of the decision is attached to this report. In that decision, the Board indicated that it was prepared to approve the applied-for pump station. This report deals with the matters respecting the existing La Corey terminal.

3 CONCERNS REGARDING THE EXISTING LA COREY TERMINAL

The concerns expressed at the hearing regarding the existing La Corey terminal were in the following categories:

- o odour,
- o noise, and
- o truck traffic.

3.1 Odour

3.1.1 Views of the Applicant

AEC said that its existing terminal consisted of a truck pit to receive truck deliveries of bitumen, a storage tank to store condensate for subsequent blending with the bitumen, a number of storage tanks for the blended product, and pumping equipment for injection of blended bitumen into the main pipeline.

AEC acknowledged that a number of odour complaints had been received since the truck terminal went into operation in April 1986. These were generally thought to be the smell of hydrocarbons or hydrogen sulphide (H_2S). It indicated that, in response to these complaints, it had participated in and commissioned a number of third-party odour studies at the existing La Corey terminal, and that these studies had not pinpointed the terminal as the source. The studies did, however, show that detectable levels of hydrocarbons and H_2S were found in the area. The levels of H_2S were well below the existing environmental standards. AEC concluded from its studies that the timing of the reported odour incidents could not be correlated with potential activity at the terminal.

It identified the truck pit and the vent of the condensate tank as potential sources of odour at the existing site. AEC said that vapours could be vented from the top of the condensate storage tank but believed

that the volumes and concentrations were insufficient to create an air quality problem. It also believed that there were a number of other potential odour sources in the area that may contribute to the problem; however, no evidence was presented to substantiate this belief. AEC noted that the nearest other permanent source for hydrocarbon-related odour to the La Corey station is approximately 10 to 15 kilometres away, although trucking of heavy oil in the area would be a closer source.

AEC also stated that, in order to prevent the truck pit from being a potential odour source, it had instructed its staff to ensure that the sliding doors to the pit are open only during off-loading operations which generally last about 20 minutes. It also indicated that at present there are only two truck deliveries per day which are not expected to increase in the near future.

AEC stated that it was ready to rectify the odour problem but was unable to conclude that the existing La Corey terminal was the cause.

3.1.2 Views of the Interveners

A number of interveners appeared at the hearing to discuss their environmental concerns about the La Corey site. Ms. Dyck indicated that she travelled past the La Corey terminal daily on her way to and from work and quite often noticed an odour like "rotten eggs" in the vicinity of the terminal. The strength of the odour varied and was more noticeable closer to the terminal. She had not noticed this odour prior to the commencement of operations at the La Corey terminal.

Ms. Szymanski stated that she noticed odours in the valley near the terminal during the morning and in the evening. She indicated that although there was some musky odour from the nearby slough prior to the operation of the terminal, the present odours were very strong and smelled like rotten eggs and sulphur. She also indicated that the smell was quite pronounced in her house and yard on some days. Ms. Szymanski stated that she had concerns regarding possible ill effects to her health arising from the substances causing the odour.

Mr. Sabatier indicated that he had experienced odours at his property. He stated that he believed the bitumen should be dumped in a closed system to contain any vapour release. He also indicated that, for the tanks to be state-of-the-art, they should contain floating roofs and a vapour recovery system.

Ms. Spanier indicated that she had not noticed the present crude oil odour prior to the commencement of operations at the La Corey terminal. She stated that she experienced headaches from the smell and was concerned about the effects on her family's health and quality of life.

Mr. Spanier described the odour as a smell associated with crude oil and noted that he had complained about it to AEC on various occasions. He indicated that, due to power fluctuations on his property, the hydrocarbon monitor was not operative for long time periods. He therefore believed that the studies did not accurately monitor the periods of hydrocarbon concentration at his house. He also noted that he had observed various wind cross-currents on his land which do not correlate with the wind directions obtained in the monitoring trailer. He indicated that he had observed various changes in the behaviour of his cattle during periods when the odour was present.

3.1.3 Views of the Board

At the time of the site visit the Board found the facilities to be clean and only traces of hydrocarbon odours were noticeable at the truck pit. No vapours appeared to be present at the condensate tank vent. The Board believes that the terminal does not present a health hazard to local residents as long as provincial emission standards are met.

From the evidence presented, the Board believes that the residents are experiencing petroleum odours with some H_2S incidents. In general, the Board accepts that there may be brief periods of odours associated with any industrial activity at sites like the La Corey terminal. However, the Board expects operators to take all steps necessary to operate facilities to minimize these nuisance incidents. The Board recognizes the frustration for both the residents and operators when attempting to determine the source of fugitive emissions. While many variables make it difficult to pinpoint the source for a particular incident, the Board believes that the proximity of the La Corey terminal to the odour incidents suggests it is the likely source of emission.

The Board notes that the condensate storage tank at the existing terminal does not have a vapour recovery or containment system. It also notes that the Stanley Associates February 1988 odour study based its conclusions on the concentrations of H_2S obtained from only one batch of condensate while AEC stated that there is a variation in the concentration of H_2S with different batches of condensate. It also deems that a number of assumptions were used to draw conclusions in the Stanley Associates study which were not validated.

The Board has reviewed AEC's report on an odour incident that occurred on 21 March 1988 wherein AEC's consultant concluded that the terminal was not the source of the odour reported by a local resident. From the evidence given, an odour complaint was received from the Spanier household that was generally correlatable with the filling of the condensate tank. The Board also notes that, although the average ground-level concentration of H_2S measured between 1600 and 1700 hours was 5 parts per billion (ppb), the peak value was 26 ppb, and a 15-minute average was approximately 15 ppb. Therefore, there were

periods of time when the H_2S concentrations exceeded the odour threshold. With the condensate tank being filled within a similar time frame as the odour was noted and because the monitor at the Spanier house was downwind from the terminal during this period of activity, the Board believes that it is just as reasonable to conclude that the condensate tank was the likely source during this particular incident and may be a contributor during other odour incidents.

The Board is aware that there may be other sources of odour in the general area; however, it finds difficulty in accepting those other sources as the cause of concern surrounding the AEC facilities because of the much greater distance that vapours must travel from these other facilities and the inordinate release that would be necessary to produce the levels detected in the area of the La Corey terminal.

The Board believes that in order to eliminate the condensate storage tank as a potential source of odours, a vapour recovery system or an internal floating roof with a fixed cone roof would have to be installed on this tank at a cost of some $75 000. While industry practice at similar installations appears to favour internal floating roof tanks for handling sour hydrocarbons, the Board is not convinced that such modifications should be made until all other reasonable remedies to relieve the problem are pursued. The Board is influenced in this regard by AEC's evidence that the throughput at the truck pit could decrease with the proposed new pump station such that the modifications may be unnecessary.

The Board notes that there is some odour resulting from the bitumen off-loading. However, as the time period for this activity is short, it does not believe this to be the main problem if good operating practices at the pit are maintained. It encourages AEC to remain vigilant about reducing odour effects and to ensure that the transfer operation remains clean and efficient at all times.

The Board also sees some merit in continuing the communication between AEC and the local residents during periods of unusual activity or odour occurrences. It suggests that a system be set up that would permit representatives of the local residents and AEC to meet regularly to discuss concerns and incidents. Staff from the Board's Bonnyville area office could attend as observers and to facilitate transfer of information between the two parties.

The Board will also request that AEC and the local residents set up an adequate system to catalogue the incidence of odour emissions, their frequency, and their correlation with activity at the station. Incident reports and the disposition by AEC should be reported to the Board's area office promptly. If the records over the next year show intermittent odour problems or the nature and frequency of incidents suggest continued severe odour problems over a period before the end of the year, the Board expects AEC to modify its equipment to rule out the

La Corey terminal as a source of persistent odour. The Board requests AEC to prepare a suitable plan for monitoring odour incidents and potential causes in conjunction with the residents and to submit it to the Board within a month from the release of this report.

3.2 Noise

Along with the air quality study, AEC had its consultant conduct a noise survey at the La Corey terminal and concluded that the operation of the La Corey terminal does not result in significant noise levels at nearby residences. In response to questioning, AEC committed to ensure that the current and any future noise standards will be met at its existing and proposed facilities.

The interveners questioned AEC's noise survey and retained an acoustical expert, Mr. Eugene Bolstad, to assess the validity of AEC's noise survey report Mr. Bolstad indicated that some of the calculation procedures used in the report were incorrect. His review of the noise levels presented in the report indicated that there were a number of anomalies that were not satisfactorily explained. Because of these concerns, Mr. Bolstad said that in his opinion no conclusions could be drawn for the report and the validity of the survey was questionable.

The interveners indicated that they did not consider the noise from the existing facility to be a problem at this time. There was some concern, however, that the proposed new pump station may lead to unacceptable noise levels for the residents in a rural setting.

While the Board has some concerns about the methods and procedures used to conduct the noise surveys, it is satisfied that AEC has committed to employ whatever measures are necessary to ensure that the facility will comply with the current and/or future noise guidelines and standards. Community concerns about noise could also be part of the monitoring program recommended in Section 3.1.3.

3.3 Truck Traffic

Ms. Dyck and Ms. Szymanski expressed concerns regarding the truck traffic due to the existing facility.

AEC stated that the existing facility currently handles an average of two truck deliveries a day. However, although it is designed to unload up to 26 trucks per day, that level of traffic has never been achieved. It stated that the installation of the proposed new facility should lead to a general reduction of truck traffic to this terminal because producers in the area would be able to ship their product by pipeline to the pump station as a result of the additional pumping facilities at this site. AEC indicated that lateral pipeline projects to this pump station were being planned.

The Board does not believe that the current and expected truck off-loading frequency presents an unusual traffic problem. However, should such an increase occur, the Board expects AEC to provide appropriate advice to those delivering bitumen to its facility regarding the concerns of the residents in the area.

4 INTERVENERS' CONDITIONS

The interveners requested a number of conditions to be imposed on the existing facilities. The following outlines the Board's views on these conditions.

1. A floating roof should be installed with a vapour recovery system on the condensate storage tank.

   The Board agrees that the condensate storage tank is one of the possible sources of odour in the area. If a significant odour problem persists over the next year, the Board expects AEC to install either a floating roof with a fixed cone roof or a vapour recovery system on the condensate tank.

2. The truck terminal should have a continuous H_2S monitor.

   The Board believes that installation of a floating roof or vapour recovery system by AEC on the condensate tank would make all the tanks in the facility a closed system. Although bitumen off-loading could be an odour source, it would be so for short periods of time and should not be detectable off lease. The Board notes that the potential H_2S sources are not high volume or of high concentration and do not warrant installation of a permanent monitor.

3. There should not be an outlet for the fluids contained in the dikes around the tanks.

   The Board notes that fluids released from within the dike area must meet specific provincial standards for surface runoff. The Board expects AEC to closely monitor the contained fluids for conformance to these standards. It does not believe that a special condition is required.

4. Caution signs should be installed on the highway and AEC should be responsible for notifying the truck drivers of school bus stops along the highway.

   The Board does not believe this to be a serious problem given the low level of truck traffic per day delivering to the facility at this time. Notwithstanding that view, the Board requests AEC to alert its trucking contractors and others using the facility of this local concern, particularly if the truck traffic should increase significantly.

5. AEC should set up a program for dust control along the highway and roads.
   The Board does not expect this to be a problem with the current truck traffic to this facility; however, it believes that, if the frequency of trucks should increase, AEC should discuss the problem with the residents and the relevant authority responsible for the roads and come to a reasonable solution.

6. AEC should have a 24-hour phone number in case of emergencies.
   The Board notes that AEC indicated its 24-hour phone number in the course of the hearing and believes that it would be beneficial for AEC to further highlight this number in a separate letter to the residents.

7. AEC should install a closed system for off-loading bitumen.
   The Board recognizes AEC's evidence that only two trucks per day are off-loaded presently and that the off-loading process can be accomplished in about 20 minutes. Because of the low frequency of truck traffic and the short time-span of activity, the Board believes that a closed system is not necessary for this activity. However, the Board concurs with AEC's operational procedure to keep the sliding doors closed at all other times.

8. A permanent H_2S monitor should be placed on the Spanier and Szymanski properties and a consistent policy should be imposed regarding monitoring and access to the information.
   The Board notes that large emissions at significant concentrations are not expected from the existing terminal. Therefore, the Board does not believe that a permanent monitor is necessary at the present time. It expects, however, that a program should be set up by AEC to correlate local resident complaints and terminal activity with the co-operation of the nearby residents.

DATED at Calgary, Alberta, on 14 July 1988.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Board Member

J. D. Dilay, P.Eng.
Acting Board Member

K. G. Sharp, P.Eng.
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
AEC Pipelines (AEC) J. W. Beames, Q.C.	M. J. Benson J. R. Jakowski, P.Eng. B. J. Bradley, P.Eng. A. Lamb, P.Eng., of Stanley Associates Engineering Ltd. B. Somerville, P.Eng., of Colt Engineering Corporation
J. Dyck	J. Dyck
F. & M. Szymanski, G. Sabatier, W. & G. Spanier, P. T. Johnston	F. Szymanski G. Sabatier W. Spanier G. Spanier E. H. Bolstad, P.Eng., of Bolstad Engineering Associates Ltd.
Energy Resources Conservation Board staff N. C. Harris, P.Eng. R. Wright, P.Eng.	

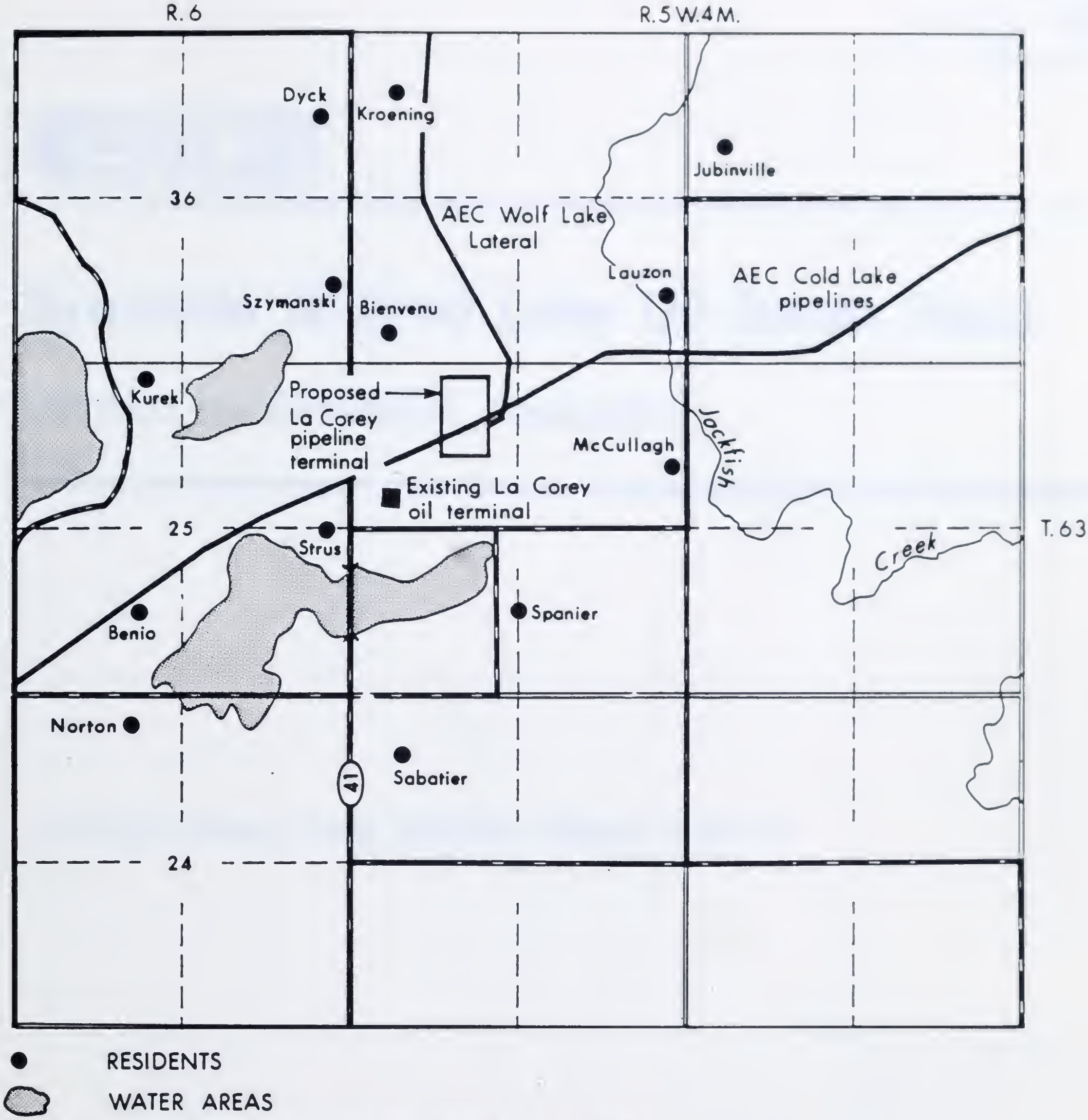


FIGURE 1 LA COREY PIPELINE TERMINAL AREA

Application No. 871983

AEC Pipelines

ERCB

Syncrude Mildred Lake Oil Sands Plant

Decision on Expansion Application

* Includes Board Panel Decision Report D 88-6

June 1988

ERCB

Syncrude Mildred Lake Oil Sands Plant

Decision on Expansion Application

INCLUDED IN THIS BOARD DECISION REPORT AS APPENDICES ARE THE BOARD PANEL DECISION REPORT D 88-6 AND A REPORT FROM THE SYNCRUDE EXPANSION REVIEW GROUP.

June 1988

SYNCRUDE MILDRED LAKE OIL SANDS PLANT
DECISION ON EXPANSION APPLICATION

Report D 88-7 published June 1988

Published by:

Energy Resources Conservation Board
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Calgary, Alberta
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Telex 03-821717

Price: $10.00

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SYNCRUDE EXPANSION
MILDRED LAKE OIL SANDS PLANT

Decision Report D 88-7
Application 870593

1 INTRODUCTION

Syncrude Canada Limited (Syncrude) applied pursuant to section 14 of the Oil Sands Conservation Act for approval of an amendment to existing Approval No. 4973 to provide for the following:

- increased yearly production of marketable hydrocarbons from 8.375 million cubic metres (10^6 m^3) to 10 x 10^6 m^3 beginning 1 January 1988, from the currently approved facilities,
- increased yearly production of marketable hydrocarbons to 15 x 10^6 m^3 beginning 1 February 1993,
- production period to 31 December 2018,
- new oil sands mining and discard disposal areas, and
- construction and operation of the new facilities to mine and process oil sands and to produce synthetic crude oil.

The Board supplemented the normal regulatory review of the expansion proposal by establishing a consultative review group called the Syncrude Expansion Review Group (SERG). SERG comprised representatives of the Fort McKay Band (Band), Syncrude, Alberta Environment (A.Env.), Alberta Forestry, Lands and Wildlife (AFL&W), and ERCB staff. This group, chaired by the ERCB, was charged with identifying the major issues and problems associated with application, identifying and resolving concerns where possible outside the context of a public hearing, and promoting dialogue among the Band, Syncrude, and government departments. A final report of the SERG was received by the Board on 9 March 1988.

A Notice of Filing of the application was published on 22 May 1987 which informed the public of the proposed expansion and invited interested parties to contact the ERCB. Alberta Energy Company (AEC), Chevron Canada Resources Ltd. (Chevron), Alberta Power Limited (APL), Alberta Oil Sands Technology and Research Authority (AOSTRA), Oleophilic Sieve Development Canada Ltd. (OSDC), Alberta Trappers Association, and the Band responded to the notice.

The concerns of AEC, APL, and AOSTRA related to relocation of pipelines, power lines, and roads necessitated by the expanded operations. These concerns were dealt with by Syncrude and each of AEC, APL, and AOSTRA;

and the Board is satisfied that the issues were resolved. The Chevron intervention related to activities proposed on section 12-92-11 W4M on which Chevron has the oil sands rights. Syncrude subsequently deleted this area from its proposed project area.

The concerns of the Alberta Trappers Association were addressed by Board staff through a consultative mediation-type process.

To consider issues regarding the interventions of OSDC which remained unresolved the Board convened a hearing on 24 March 1988.

This report sets out the background to the Board's process, the reasons for its decision, and conditions.

2 RESOLUTION OF ISSUES BY A CONSULTATIVE PROCESS

The Syncrude Expansion Review Group (SERG) process was successful in promoting issue-by-issue dialogue and better understanding between the ERCB, the Band, Syncrude, and government departments and resolved concerns outside the context of the quasi-judicial public hearing. SERG recommended that the application be granted without specific conditions except those that the ERCB might otherwise place. The SERG report is attached as Appendix A.

The Board notes the significant achievements of SERG in carrying a number of difficult issues to amicable and satisfactory conclusions. The Board is optimistic that the consultative process pioneered here, and which has resulted in nearly unanimous endorsement by the participants, may find broader application in other matters to come before the Board.

3 BOARD CONCLUSIONS

3.1 The SERG Recommendations

The Board concurs in the SERG recommendations which would result in amending the Syncrude approval in the following respects:

- the expanded project area,
- the requested new mining areas,
- the new process plant facilities,
- Syncrude's proposed sulphur recovery level,
- yearly production of marketable liquid hydrocarbons of 15×10^6 m^3,
- the date of approval to be extended to the 31 December 2018, and

- Syncrude to obtain Board approval prior to construction of any new out-of-pit overburden disposal sites associated with the expansion.

3.2 Alberta Trappers Asssociation Intervention

J. Rogers, on behalf of the Alberta Trappers Association, raised concerns about the environment, waterfowl and migratory birds, employment, traditional lifestyle, and energy conservation matters. These were discussed at meetings among Mr. Rogers, Syncrude, and Board staff. Board staff summarized the concerns and the status of the intervention in a Memorandum of Understanding. This document, along with a number of comments and questions of Mr. Rogers, was received by the Board. The document concludes that issues raised by Mr. Rogers were effectively and reasonably responded to by Syncrude, and that the issues are being appropriately pursued by the ERCB or others.

The Board is satisfied that the concerns raised by Mr. Rogers have been effectively and correctly dealt with.

3.3 Oleophilic Sieve Development of Canada Limited Intervention

The intervention of OSDC was heard by the Board on 24 March 1988 and is dealt with in Board Decision Report D 88-6 (see attached Appendix B). In brief, that decision finds that while the warm slurry process extraction method proposed by Syncrude for use in the expansion is satisfactory, there is a need for renewed and concerted efforts to develop improved technology to resolve concerns respecting tailings sludge bulking and toxicity effects, and enhanced bitumen recovery. The Board plans to initiate discussions with industry and government which could lead to establishment of guidelines respecting those concerns. Also, the Board concludes that demonstration of desired and potentially beneficial technology at existing operational oil sands mining projects is a matter of importance, irrespective of the operatorship of the project or the ownership of new technology to be tested. It therefore plans to explore the possibility of a joint industry/government program, headed by a small advisory board, to facilitate the necessary research and testing respecting these matters.

4 BOARD DECISION

Having regard for its findings and its responsibilities under the Oil Sands Conservation Act, the Board, with the authorization of the Lieutenant Governor in Council, is prepared to revise Approval No. 4973 to permit the modifications applied for. The approval would be in the form set out in Appendix C and would be subject to the terms and conditions therein contained and such other conditions that may be imposed by the Minister of the Environment as it affects matters of the

environment and the Associate Minister of Public Lands and Wildlife as it affects land and resources that are property of the Crown in the right of Alberta.

DATED at Calgary, Alberta on 3 June 1988.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

APPENDIX A

SYNCRUDE CANADA LTD.
MILDRED LAKE PLANT

MILDRED LAKE PLANT EXPANSION APPLICATION NO. 870593

A Report Of The

SYNCRUDE EXPANSION REVIEW GROUP

To The

ENERGY RESOURCES CONSERVATION BOARD

MARCH 1988

9 March 1988

Mr. G. J. DeSorcy
Chairman
Energy Resources Conservation Board
640 Fifth Avenue S.W.
Calgary, Alberta
T2P 3G4

Dear Mr. DeSorcy:

I have the honour to transmit the report of the Syncrude Expansion Review Group.

Yours truly,

R G Evans

R. G. Evans
Chairman
Syncrude Expansion Review Group

RGE:sc

cc: SERG Participants

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EXECUTIVE SUMMARY

At a meeting of senior executives of Syncrude Canada Ltd. (Syncrude), Alberta Environment (A.Env.), Energy Resources Conservation Board (ERCB), and Fort McKay Indian Band (the Band) in Edmonton on 18 August 1986, discussion of the potential application by Syncrude for an expansion of its Mildred Lake Plant took place. It was agreed that a group be established to facilitate the ERCB application review and that it be called Syncrude Expansion Review Group (SERG). The participants of SERG were representatives of the Band, Syncrude, A.Env., Alberta Forestry, Lands and Wildlife (AFL&W), and the ERCB. It was also agreed that the ERCB would chair SERG meetings.

In an attempt to identify and, where possible, resolve concerns outside the context of a public hearing, and to promote dialogue among the Band, Syncrude, and Government Departments, SERG was charged with identifying the major issues and problems associated with the application and giving consideration to all aspects of the proposal, including environmental impact and the merits of the expansion in terms of resource and social benefits. Ultimately SERG was to advise the ERCB, A.Env., and AFL&W regarding areas of agreement and non-agreement.

SERG convened a total of eleven times. Issues were addressed such as need for mining and discard areas, process plant modifications, technology selection, fuel utilization, environmental impacts, socioeconomic impacts, and fulfilment of the public interest, including employment and business opportunities for local native residents. Environmental issues of particular significance which were discussed were sulphur recovery, sulphur dioxide, heavy metal and particulate emissions, acid deposition, ambient impacts, water management, and reclamation.

SERG agreed that it was desirable to retain a consultant to conduct an independent assessment of claims made by Syncrude in its application to the ERCB. The consultant assessed the capability of proposed technology to optimize hydrocarbon yield, limit sulphur dioxide (SO_2), and metals emissions rates to current levels, report on alternative process technology which would have the possibility of being the best practical technology, and provide a measure of the cost to achieve lower sulphur and heavy metals emissions.

SERG was succcessful in bringing the Band leadership and Syncrude management together, identifying issues requiring resolution and documenting areas of agreement or disagreement. As a result this report, which focuses on the issues successfully resolved among the parties, was produced.

SERG recommends that the application be approved without specific conditions except those that the ERCB may otherwise place. The SERG participants believe that, for the people involved, the issues discussed were more thoroughly reviewed and analyzed and better understood than they would have been at a public hearing. A number of issues were identified for handling by other standing committees or regulatory agencies.

1 INTRODUCTION

1.1 The Application

Syncrude Canada Ltd. (Syncrude) submitted Application No. 870593, pursuant to section 14 of the Oil Sands Conservation Act, for approval of the Energy Resources Conservation Board (ERCB) to amend Approval No. 4973 to allow increased production of marketable hydrocarbon from 8.37 million cubic metres per year to 10 million cubic metres per year beginning 1 January 1988 from the currently approved facilities, a further increase in production to 15 million cubic metres per year beginning 1 January 1993 from the expanded plant, an extension of the discard site and mining areas within the requested project area (Figure 1) and a 5-year extension of the production period to 31 December 2018.

The application included a Technical Report and an Environmental Impact Assessment (EIA). The EIA consisted of a "Biophysical Impact Assessment" and a "Social and Economic Impact Assessment".

1.2 Notice of Filing of Application

As a separate but parallel activity, not directly a part of the SERG process, a Notice of Filing of the application was published by the ERCB on 22 May 1987 to inform the public or any interested parties of the application by Syncrude. The Notice invited interested parties to contact the ERCB with their concerns. SERG participants were informed of all the concerns raised which were as follows:

(a) AEC Pipelines (AEC)

AEC was concerned about any impact, present or future, on the integrity of pipeline right of way, and pipeline and pumping facilities located in the project area.

(b) Chevron Canada Resources Limited (Chevron)

Chevron retains the oil sands rights to section 12-92-11 W4M which was included in Syncrude's application area. Clarification of the issue was requested by Chevron.

(c) Alberta Power Ltd. (APL)

APL's submission stated that its interest was the cost of relocation of several power lines in the expansion area, and that, since the power lines were covered by Government easements or licences, the costs would be Syncrude's responsibility. APL also stated that its submission was for information purposes and was not an intervention.

(d) Oleophilic Sieve Development of Canada (Kruyer)

The Kruyer submission expressed concerns related primarily to technical process matters which dealt with the extraction process, tailings impoundment, and reduction in sludge accumulation.

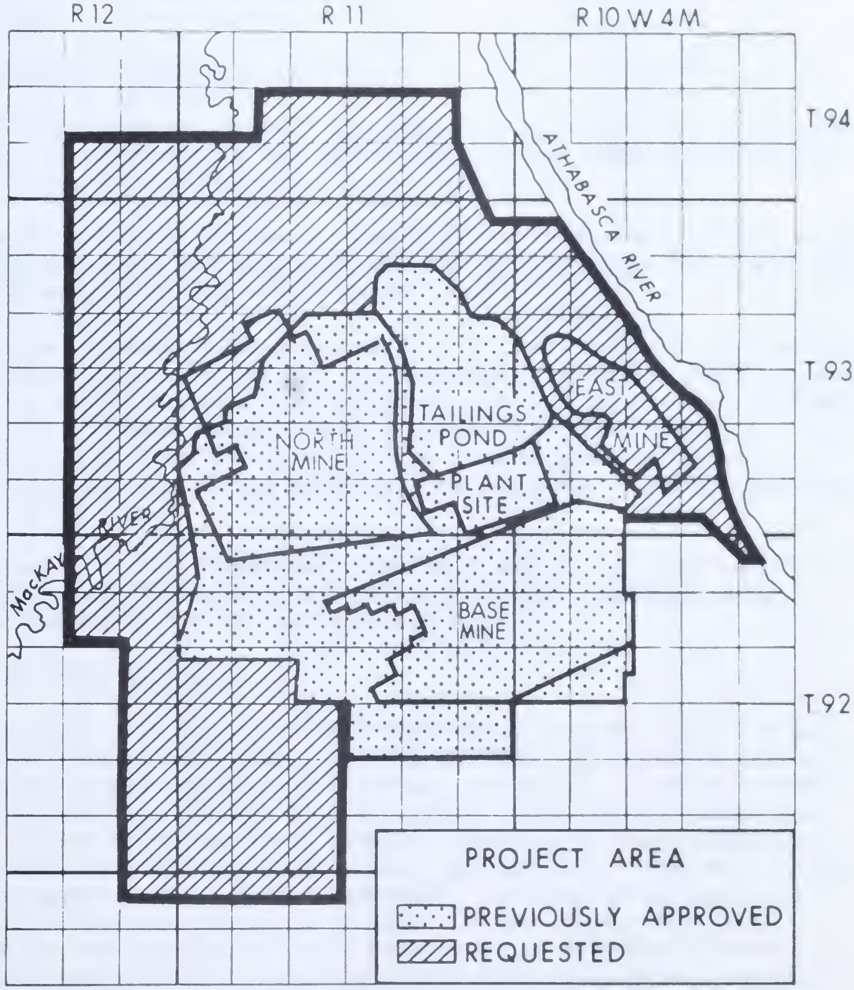

FIGURE 1 SYNCRUDE PROJECT AREA

(e) Alberta Trappers Association, Fort McMurray Local

Jim Rogers, representing the Fort McMurray Local, raised a number of issues relating to employment for locals and environmental matters.

(f) Fort McKay Indian Band (the Band)

The Band formally informed the ERCB that it wished to reserve the right to intervene in any public hearing that might be conducted with regard to the Syncrude plant expansion.

(g) Alberta Oil Sands Technology and Research Authority (AOSTRA) raised questions about the proposed new sand disposal area which was shown to cover an existing AOSTRA access road.

The ERCB also discussed the application with the Department of Community & Occupational Health (C&OH) and the Fort McMurray Health Unit. It was stated that the Health Unit was responsible to assist the Band on health matters and, if there was a need or a request to do so, that Dr. Nicholson, of Health Unit 27 of Fort McMurray, would respond. Dr. Nicholson stated that he would contact Syncrude directly regarding health-related issues.

For resolution of the issues and concerns raised by the interested parties, several discussions and, where necessary, meetings among Syncrude, the ERCB, and the parties were held.

2 SERG PROCEEDINGS

In anticipation of a September 1986 application from Syncrude for an expansion of its Mildred Lake facility, the ERCB, with the concurrence of Syncrude, representatives of the Band, and A.Env., decided to deal with the application through a review group. This group, called the Syncrude Expansion Review Group (SERG), consisted of representatives from Syncrude, A.Env., AFL&W, the Band, and the ERCB. The ERCB chaired the review group. The terms of reference, provided in Appendix A, detail the scope and objectives of SERG. It was clear that final decisions on the application would have to be in conformance with established legislation and that the participation of A.Env. could not be construed as fettering the independence of that department or its minister.

SERG facilitated the review of Syncrude's expansion application and identified and resolved a number of issues. In so doing, the objectives of SERG were to maximize the co-operation and communication between the parties and to maximize each party's satisfaction with the review and approval procedure.

SERG consulted with Syncrude prior to the filing of the application to identify significant issues of mutual interest and advised Syncrude on problems and concerns which had to be dealt with in the application. During this consultation, Syncrude filed a Preliminary Disclosure Document which was subsequently replaced by Application No. 870593.

SERG, in its meetings, dealt with the disclosure document, Application No. 870593, questions raised by the ERCB staff, by Government Departments, and by the Band, and Syncrude's responses to the questions.

SERG considered matters relating to energy resource conservation, economics, orderly and efficient development of the resource, on-site environment protection, pollution control, regional and local environmental impacts, socioeconomic impacts, the fulfilment of the public interest, and employment and business opportunities for local native residents.

SERG participants agreed that the application be circulated through Government Departments. The concerns raised were tabled with SERG. Thus the normal ERCB application review process occurred and Government Departments forwarded their deficiency questions to the ERCB through A.Env. The ERCB prepared the deficiency list, incorporating Government Departments' questions, and forwarded it to Syncrude. Deficiency questions were answered by Syncrude and filed with the ERCB as supplemental information to the application. It was recognized that A.Env.'s permits and licences are to be handled separately.

3 THE ISSUES

The main issues discussed by SERG were as follows:

- need for mining and discard areas,
- process plant modifications,
- bitumen extraction technology,
- upgrading technology,
- alternative fuels and light ends recovery,
- sulphur dioxide (SO_2) emissions,
- sulphur recovery,
- heavy metals emissions,
- hydrocarbon and fugitive emissions,
- acid deposition and ambient impacts of emissions,
- water management, tailings impoundment, and water contamination,
- reclamation, and
- socioeconomic matters.

4 NEED FOR MINING AND DISCARD AREAS

4.1 Mining Areas

4.1.1 Ore Reserves

Syncrude submitted that the currently approved project area does not contain sufficient ore reserves to support the proposed production requirements through to the end of year 2018. Syncrude proposed expanding the North Mine and adding an East Mine, as shown in Figure 2. This would provide approximately 64 per cent more ore reserves than required. Syncrude submitted that this excess reserve was necessary to provide for mine design refinement, access corridors, mining and extraction losses, planning flexibility, and maintenance of required

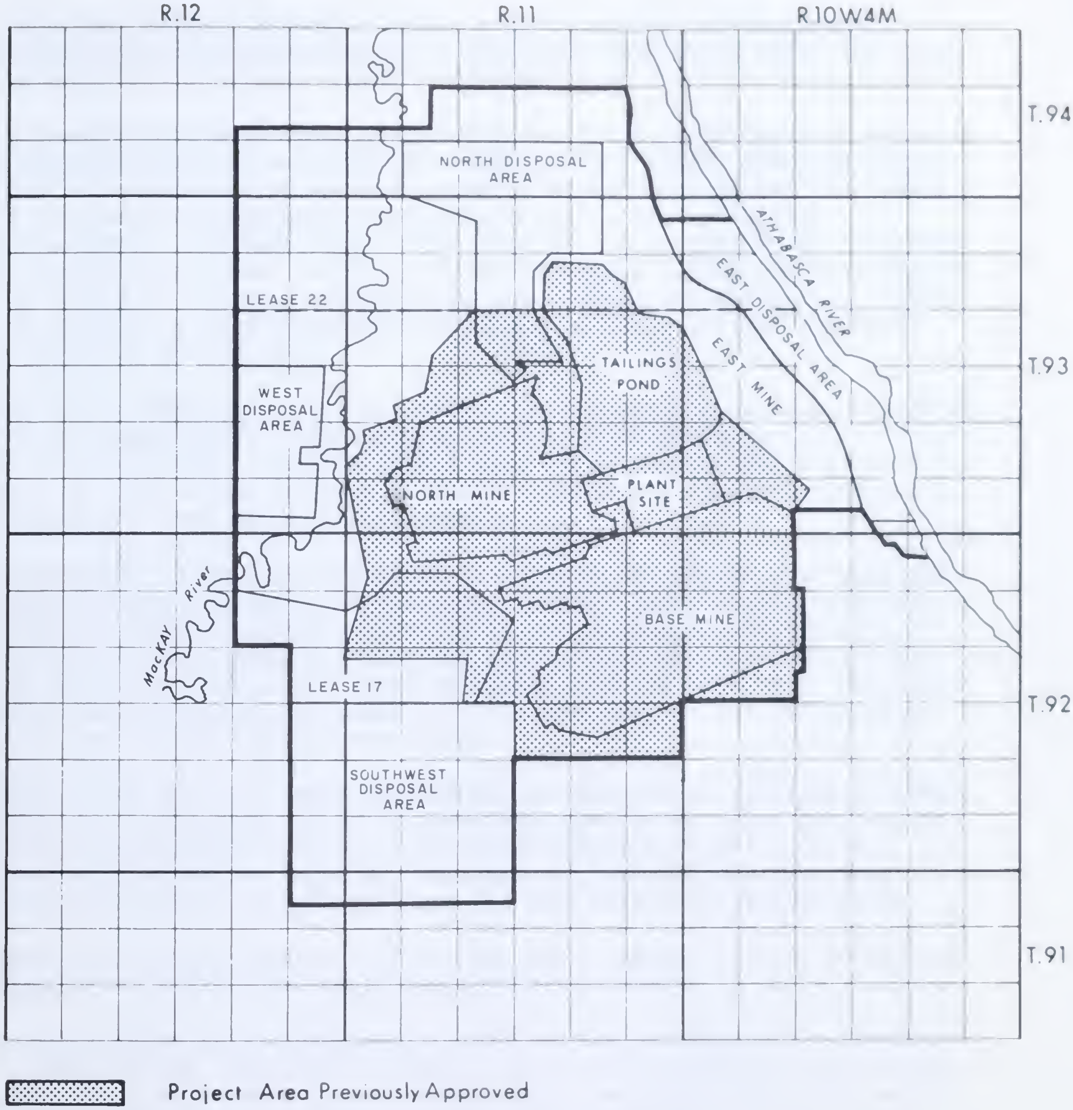

FIGURE 2 COMPARISON OF THE CURRENTLY APPROVED PROJECT AREA WITH THE AREA REQUESTED FOR THE EXPANSION PROJECT (REPRODUCED FROM SYNCRUDE APPLICATION)

production rates. Syncrude further submitted that, although the application requests approval for operations only until 2018, the plans are based on operations continuing beyond then.

A concern was raised about not showing any mining activities to occur in a location west of the plant site under the NT1 dump. Syncrude stated that this dump will be moved and the ore under it mined but the timing of this would be handled in conjunction with annual mine plan discussions. Syncrude stated that the dump is not considered a barrier to mining activities. Parts of it will be moved during the plan period. The timing of removing further waste will depend on the need to access the area which is constrained from mining by factors other than the location of the NT1 dump.

The ERCB, referring to letters from it to Syncrude concerning removal of the NT1 dump, stated that the dump must be relocated prior to 31 December 2003. The ERCB agreed that the timing of the removal of NT1, as well as the recovery of the ore underneath, could be handled in conjunction with operational approvals.

In response to concerns raised about the need for 64 per cent more ore reserves than required, Syncrude again stated that this was necessary for, among other reasons previously listed, planning flexibility. Syncrude further responded that the applied-for area has been planned for operations that would continue beyond 2018 and that if it were felt that the operation would cease in 2018, then the current mining plans would have to be altered accordingly.

SERG agrees that oil sands development is required to increase synthetic crude oil production and to achieve this, new mining areas are required. SERG further agrees that Syncrude should have some provision for planning flexibility and thus the requested new mining areas, those being the North Mine expansion and the East Mine, are satisfactory.

SERG also believes that the final mine limit approval should be handled through the ERCB annual mine plan approval process.

As for concern raised dealing with NT1 and the associated ore underneath it, SERG agrees that this ore must be recovered and that its recovery plans would be handled in conjunction with the annual mine plan review process conducted by the ERCB at the time of mining activity in the area.

4.1.2 Marine Ore

Syncrude submitted that recovery of bitumen from marine ore is similar to that of estuarine ore of comparable grade.

In response to a concern that Syncrude's submission was different from previous submissions dealing with marine ore, Syncrude stated that many tests have been conducted in recent years and the results lead Syncrude to believe that there would not be any resource recovery loss in extracting bitumen from this ore as compared to any other ore.

Although Syncrude stated that the extraction test results on marine ore were considered proprietary, it was willing to allow the Board staff access to the information provided it was kept confidential.

SERG agrees that this information pertains to a detailed technical matter which concerns only the Board staff and Syncrude and would be better discussed with Board staff outside the SERG process.

4.2 Discard Areas

4.2.1 Overburden and Centre Reject

Syncrude submitted that initially, and until the pits mature, overburden material and portions of the centre reject or waste material in the ore body would be placed in out-of-pit overburden discard sites. The proposed discard sites have been located over areas in which oil sands mining is not attractive.

In response to a concern raised about the fact that the East Mine overburden disposal area was designed to be above the 1-in-50-year Athabasca River flood level instead of the 1-in-100-year level, Syncrude has provided supplemental information that 1-in-100-year flood would not impact the dump or the river. Prior to development Syncrude will have to apply for and receive the approval of A.Env. for this disposal area.

In response to a concern that Syncrude's supplemental drawings S-4 to S-7 indicate discard disposal activities which may result in some sterilization of mineable oil sands in final pit walls, Syncrude agreed that, if it was economic to mine ore in these areas, it would be mined. Syncrude noted that placing waste against a pit wall does not sterilize ore. Syncrude also stated that, as the drawings referred to are only preliminary, pit wall and discard site final limits are better handled in conjunction with the annual mine plan discussions.

SERG agrees that overburden disposal sites will initially be required out-of-pit. However, SERG notes that Syncrude is required to obtain the normal Board and A.Env. operational approvals prior to construction of any out-of-pit overburden disposal sites associated with the proposed expansion activities.

SERG agrees that in-pit discard disposal should not sterilize any potentially recoverable ore in the final pit walls. SERG further agrees that final pit and discard disposal limits should be handled in conjunction with the annual mine plan discussions.

4.2.2 Tailings

Syncrude submitted that it plans to dispose of tailings sand outside of the existing tailings pond in the year 1990, and to use the existing tailings pond only for interim sludge and water storage. In order to do so, additional sand that cannot be accommodated in the mined-out pits must be placed out-of-pit. Syncrude has identified two possible out-of-pit sand disposal areas, both of which are considered

unattractive for oil sands mining. Syncrude proposes to utilize the area in the southwestern corner of the proposed project area to accommodate the out-of-pit tailings sand requirements through to the year 2018.

Syncrude further submitted the following schedule for tailings operations:

(a) complete construction of a new sand disposal site in the southwest corner of the development area and commence operation by 1990,

(b) commence disposal of tailings sand in the Base Mine pit between 1992 and 2002, to initiate construction of water and sludge contained areas, and

(c) move water and sludge from the out-of-pit tailings pond into the Base Mine in-pit sludge disposal area as early as 1997 or, at the latest, during the 2013-2018 time period.

In response to a question raised about the future plans for the existing tailings pond once all sludge was transferred from it to mined-out pits, Syncrude indicated that it has no plans to fill in the tailings pond with sludge or sand, but instead proposes to reclaim the tailings pond bottom as dry land. Some portions of the dikes might be removed to accommodate mining and/or to re-establish final drainage patterns to the north portion of Beaver Creek.

The plans for disposal of sludge in the development and reclamation plan which Syncrude outlined in the application are based upon fines capture rates of 25 per cent in beached tailings sand and a sludge of 33 per cent solids content. These planning criteria are ones in which Syncrude has confidence. These criteria, along with structural constraints, are used in developing plans for the transfer of tailings sludge into the mined-out pits. Syncrude also indicated that it is committed to further research and development on reducing the volume of sludge. To the extent that tailings fines can be contained within geotechnically stable materials -- the tailings sand or overburden -- and to the extent that higher density can be obtained on the residual amount of sludge, the volume of ultimate sludge accumulation to be disposed of in the final landscape can be reduced. SERG recommends a continued emphasis on this important area of research.

In response to a question raised concerning the attractiveness of mining the oil sands in the proposed tailings sand disposal area, Syncrude stated that it planned drilling the area to confirm underlying resource data.

SERG agrees that, based on the information supplied, additional sand storage area is required. However, SERG also agrees that Syncrude should not start construction of any tailings sand disposal area until normal operational approvals are obtained from the ERCB and A.Env.

4.3 Project Area

4.3.1 Expansion West of the MacKay River

Syncrude submitted that, although its current plan does not have a disposal area located on the west side of the MacKay River prior to year 2018, it is essential that the area be approved to allow for planning flexibility. Syncrude further noted that if the ERCB were to include this area within the approved development area, Syncrude would be required to obtain specific operating approvals from the ERCB and A.Env. should mine plans change in the future.

The Band is satisfied with the explanation received from Syncrude that, should an overburden disposal area west of the MacKay River be required, a bridge or conveyor facility to transport overburden across the river could be designed so as to ensure that spilled material would not enter the river.

The Band requested that the ERCB phrase any approval so that this potential development option is given appropriate consideration and the Band is consulted prior to any approvals for a river crossing of the MacKay River which may be required.

SERG agrees that should Syncrude plan on utilizing the area prior to 2018, applications to the ERCB and A.Env. respecting resource and environmental impacts would be required prior to commencement of construction of a discard site. The Band should be consulted with respect to the environmental applications.

4.3.2 North Sand Disposal Area

Syncrude submitted that its current plan does not use the North Sand Disposal Area prior to the year 2018. However, Syncrude is not prepared to provide assurances that there will never be activity north of the tailings pond or in the eastern section of Lease 22. This means that future developments may come within 3 km, if not closer, to the community of Fort McKay. The Band remains concerned about dust and noise from the potential mining operations in this area or from the disposal area if it is extended to the northern limits.

Syncrude and the Band agree that some understanding or planning basis will be required among the Band, ERCB, and Syncrude prior to developments which may result in significant nuisance impacts in Fort McKay.

SERG agrees that should Syncrude plan on using the area prior to 2018, submissions to A.Env. and the ERCB respecting environmental and resource impacts would be required for their approval, prior to commencement of construction of the sand disposal area.

4.3.3 Project Area Outline

In response to ERCB and A.Env. staff requests to justify the need for the project area, Syncrude acknowledged that the area requested is considerably larger than required to meet production and discard disposal requirements. However, Syncrude affirmed that the whole area is necessary to ensure that it has the flexibility to optimize mining operations and thereby provide for future changes in economics, technology, or other factors unknown at this time. Syncrude argued that approval of the proposed project area would allow it to handle any future mine plan changes with operational approvals rather than having to go through a full Board application review process.

SERG agrees that although the whole project area is not now required, it would recommend that the ERCB approve it to provide the flexibility requested by Syncrude. However, SERG believes that an approval issued by the ERCB at this time should specifically authorize only the mining, tailings, and discard disposal operations described. The entire area should not be approved for mining operations. On the contrary, should Syncrude propose operations other than those described, all relevant considerations, including technology and environmental control, would have to be addressed in an application to the ERCB and A.Env. Such application should be filed well in advance of operations proposed involving areas different from those described in this application, and would be dealt with by whatever review procedure the ERCB and A.Env. would deem appropriate at the time.

SERG recommends approval of the Syncrude requested project area, for the proposed operations within that project area.

5 TECHNOLOGY AND EMISSIONS VERIFICATION

During the course of the SERG discussions it was evident from the questions that arose, the complex nature of the Syncrude upgrading plant, and the novel technology proposed that independent verification of the technology and emissions claims was required. Following a SERG recommendation, the ERCB and A.Env. decided to retain a consultant and agreed to share the costs. Mr. D. Ronald Hickey was the consultant selected.

The major objectives of the study agreed to by SERG participants were:

- to assess the technology proposed by Syncrude to substantiate claims on hydrocarbon yield and efficiency and limitations on sulphur, vanadium, nickel, and lead emissions to the atmosphere,

- to compare the process technology proposed and the technologies selected by Syncrude with at least one alternative which would have the possibility of being the best practical technology for the expanded facility, and

- to provide a measure of what the cost might be to obtain the lowest possible sulphur and heavy metals emissions using best available technology.

The consultant was also required to communicate with Band representatives to understand their concerns and expectations, explain the study basis, and interpret the study results.

The consultant filed his draft final report in September 1987 and following review and comment by ERCB, A.Env., and the Band, the report was finalized and submitted to the Board in November 1987 and copies provided to SERG participants. The report, titled "Syncrude Expansion Emission Technology Study" (SEETS), is contained in Appendix B.

SERG participants were satisfied that the work done fulfilled the objectives of the study. The SEETS conclusions are included in the following sections.

6 PROCESS PLANT MODIFICATIONS

Syncrude proposed the following modifications and additions to the process plant:

- A new extraction plant and additional capacity for froth treatment, diluent recovery, and steam production to support the additional bitumen production.

- New bitumen hydrocracking capacity to expand the upgrading capacity. Additional hydrotreating capacity would be included to treat the additional products to finished synthetic crude oil. The additional hydrogen required by both the hydrocrackers and hydrotreaters would be supplied by new hydrogen production plants. Similarly, additional sour water treatment, amine treatment, and sulphur recovery capacity was proposed to support the expanded upgrading capacity.

- Incremental electrical generation capacity, estimated at 125 MW, would be supplied in part by gas turbine generation, with heat recovery on the turbine exhaust, balanced with generation from the existing utility plant. These modifications are dealt with in a separate submission to the ERCB under the Hydro and Electric Energy Act.

The scope of the proposed modifications is indicated in Table 1. The table lists and compares oil sands feed and bitumen and synthetic crude production rates as currently approved, and as expected on completion of the Capacity Addition Project (CAP) in 1988 and following the proposed expansion. Service factors and yields for the three cases are also provided.

6.1 New Extraction Plant

Syncrude proposed to build a new extraction plant which would use a modified process, called the Warm Slurry process. This process is an evolution in the development of water slurry oil sands processing. It is based on Syncrude research and development carried out in the past 2 years and is backed by fundamental knowledge resulting from over 20 years of research at Syncrude. Bitumen recovery efficiency is expected to be high and comparable to that from Syncrude's existing hot

water process with recovery improvements. This process selection is the result of high confidence in its performance as well as the benefits of reduced energy input. Syncrude stated that process water requirements and tailings volumes per tonne of ore from the Warm Slurry process are essentially unchanged from the present operation. Syncrude pilot testing of this process, on a variety of oil sands ores expected to be encountered in the expansion mine areas, found that recoveries meet, or exceed, the performance of the existing process.

TABLE 1: OVERVIEW OF MAJOR PRODUCTION RELATED CHANGES

Item	Current Approval	Capacity of Approved Facilities to Be Completed in 1988	Capacity Following Completion of Expansion Project
Annual bitumen feed to extraction (10^6 m^3/yr)	10.24	11.76	16.54
Average extraction and froth treatment recovery, %	93.2	93.2	93.1 *
Daily bitumen consumption by upgrading (10^3 m^3/sd)	32.3	33.4	46.9
Overall service factor	0.81	0.90	0.90
Annual bitumen consumption by upgrading (10^6 m^3/yr)	9.53	10.96	15.40
Overall synthetic crude oil yield on bitumen to upgrading	0.84	0.87	0.92
Annual synthetic crude oil production capacity (10^6 m^3/yr)	8.0	9.49	14.22
Annual naphtha production capacity (10^6 m^3/yr)	0.38	-	-
Provision for future improvements in service factor, yield, through-put and for turnaround scheduling (10^6 m^3/yr)	-	0.52	0.78
Total annual saleable hydrocarbon production applied for (10^6 m^3/yr)	8.38	10.0	15.0

* The lower recovery is a result of a slightly lower average ore grade for the expanded plant operating through the year 2018.

Syncrude considered other extraction processes, including some using water slurry-flotation or solvents, and direct oil sands coking. However, in its opinion, none of these technologies is sufficiently developed to justify inclusion in its expansion plans.

The ERCB staff pointed out that previous ERCB decisions had identified the need for improved bitumen extraction technology which would result in higher bitumen recoveries, reduced water use, increased energy efficiency and reduced tailings sludge accumulation.

SERG recognizes that the Syncrude proposed Warm Slurry process is an improvement over the existing process in terms of energy efficiency, it has addressed the matters of bitumen recovery and water use, but it does not address the concern with tailings sludge accumulation. While SERG recognizes Syncrude is active on tailings research it believes that additional work directed towards the elimination of tailings accumulation is necessary. Since the current Syncrude project schedule is such that alternative extraction or tailings treatment processes cannot be demonstrated (brought to commercial readiness) in time to be applied, SERG believes that the proposed extraction process is satisfactory.

6.2 Upgrading Technology

Syncrude proposed to use expanded bed catalytic hydrocracking as the primary upgrading technology which would be used to process the additional bitumen. This additional hydrocracking capacity would have design characteristics similar to those described by Syncrude in its CAP approved by the ERCB in 1984.

Syncrude had the following objectives in selecting a primary upgrading technology for expansion:

- reduced production dependence upon any single unit,
- increased yield of synthetic crude oil from bitumen,
- reduced coke production per cubic metre of SCO produced,
- reduced sulphur emissions per cubic metre of SCO produced,
- maintained or improved product quality, and
- optimized economics.

An additional Syncrude selection criterion was that these objectives must be achieved using proven commercial technology which would integrate well into the existing plant.

Syncrude completed a survey of available bitumen upgrading technology prior to embarking upon the CAP. This survey was updated for the expansion application. Syncrude advised that there were no substantive changes in the intervening months which altered its conclusion that expanded bed hydrocracking is the preferred option for the new upgrading capacity. Alternative bitumen hydrocracking techniques are either not fully developed and/or do not provide the significant incentives over the selected technique which would justify duplication of the effort now

under way in Syncrude to absorb the knowledge associated with this technology.

Syncrude proposed no significant modifications to the existing cokers although feedrates would be somewhat reduced.

The SEETS assessed technology and emissions aspects of Syncrude's proposed process configuration and, using a computer model, confirmed its claims on hydrocarbon yield and SO_2 emissions. The computer model, which simulated the proposed configuration, was adapted to consider an alternative high conversion process configuration. In this alternative additional bitumen produced by an expansion was fed to a high conversion hydrocracker. The SEETS found that the high conversion case did not improve synthetic crude oil yield and was less attractive than the proposed case because of significantly increased SO_2 emissions. In fact, the yield was lower by 2.0 liquid volume per cent synthetic crude product. This occurs because of the higher yield of pitch residue in the high conversion case and the fact that not as much hydrogen is consumed per unit volume bitumen feed. The consultant concluded that "in an effort to add hydrogen there is a synergism in being able to go the proposed low conversion hydrocracking/fluid coking route that is not available to direct high conversion."

SERG accepts that Syncrude's proposed upgrading addition is the optimum under the circumstances and agrees it should be approved.

6.3 Alternative Fuels and Light Ends Recovery

During the course of SERG discussions, questions were raised about the feasibility of light ends recovery (LER) and the utilization of coke for fuel. LER involves the recovery of low boiling hydrocarbons from the gas (by-product of upgrading operations). Syncrude in its 1984 application to the ERCB proposed LER and ERCB approved it. Subsequently Syncrude decided not to proceed with the installation. Syncrude maintained that neither LER nor coke utilization was attractive and they were excluded from the expansion proposal.

Recognizing the potential for change in factors which influence LER, SERG believes that Syncrude should review its feasibility from time to time.

7 BIOPHYSICAL ISSUES

7.1 Emissions and Sulphur Recovery

7.1.1 Sulphur Dioxide (SO_2) Emissions

The Syncrude proposed upgrading configuration is such that SO_2 emissions do not increase over those currently approved and SO_2 emissions per unit volume of bitumen upgraded decrease. Sulphur balances calculated for pre- and post-expansion cases using conservative assumptions show "maximum stream day" SO_2 emissions decreasing from 258 t/d to 249 t/d. To determine the probability of occurrence of SO_2 emissions different than the values shown above, Syncrude carried out a Monte-Carlo computer

simulation of the expanded plants' SO_2 emission rates. This analysis considered variations which might result from variations in feedstock quality, variations in operating conditions, and periodic equipment upsets. The distribution of calculated SO_2 emissions, displayed in Figure 3, indicates that the probability of emissions being less than 265 t/d of SO_2 is about 98.5 per cent and lower emissions are more probable.

Syncrude requested that the currently approved post-CAP performance stack emission limit of 265 t/d SO_2 on a 90-day rolling average basis be retained for an ERCB approval of the proposed expansion. Syncrude argued that it is inadvisable to set emission limits so close to actual plant performance capability that frequent exceedances are inevitable. It stated that retroactive reductions in operating approval limits, which have the effect of reducing the gap between them and expected emissions, would reduce the incentive for investments on emissions reduction. It noted that one motivation for including additional sulphur recovery facilities in the capacity addition project was to provide a significant gap between the normally expected emissions and the approval limits.

Syncrude provided the following arguments to support its position for no change to the current approval emissions limit:

- Studies to date indicate that there is no significant evidence of impact resulting from long-range transport and deposition of emissions from existing oil sands operations on even highly sensitive areas of Northeastern Alberta. Acid deposition rates are well below those in Eastern North America and Europe where problems exist. Thus, there is no compelling reason to impose retrofit investments onto existing plants.

- Ambient ground-level concentrations of SO_2 only rarely exceed Alberta Government standards and ambient air quality in the region is good (conclusion of Fort McMurray Regional Air Quality Task Force). Syncrude's main stack is so high that local ground-level fumigations from the main stack are even more rare. Thus, retrofit desulphurization of CO-boiler flue gas would have little impact on regional air quality and, if the reliability of the CO-boiler train were reduced through added complexity, it could make it worse.

- A significant consideration in the Syncrude expansion design is to minimize extensive modifications to existing plant operations, particularly critical systems. A CO-boiler retrofit would be a major modification to the most critical area of the operation.

- Syncrude has three major technical concerns with addition of SO_2 emission reduction technology to the existing coker/CO-boiler systems. These include

  (i) additional complexity and expense not warranted by environmental protection requirements;

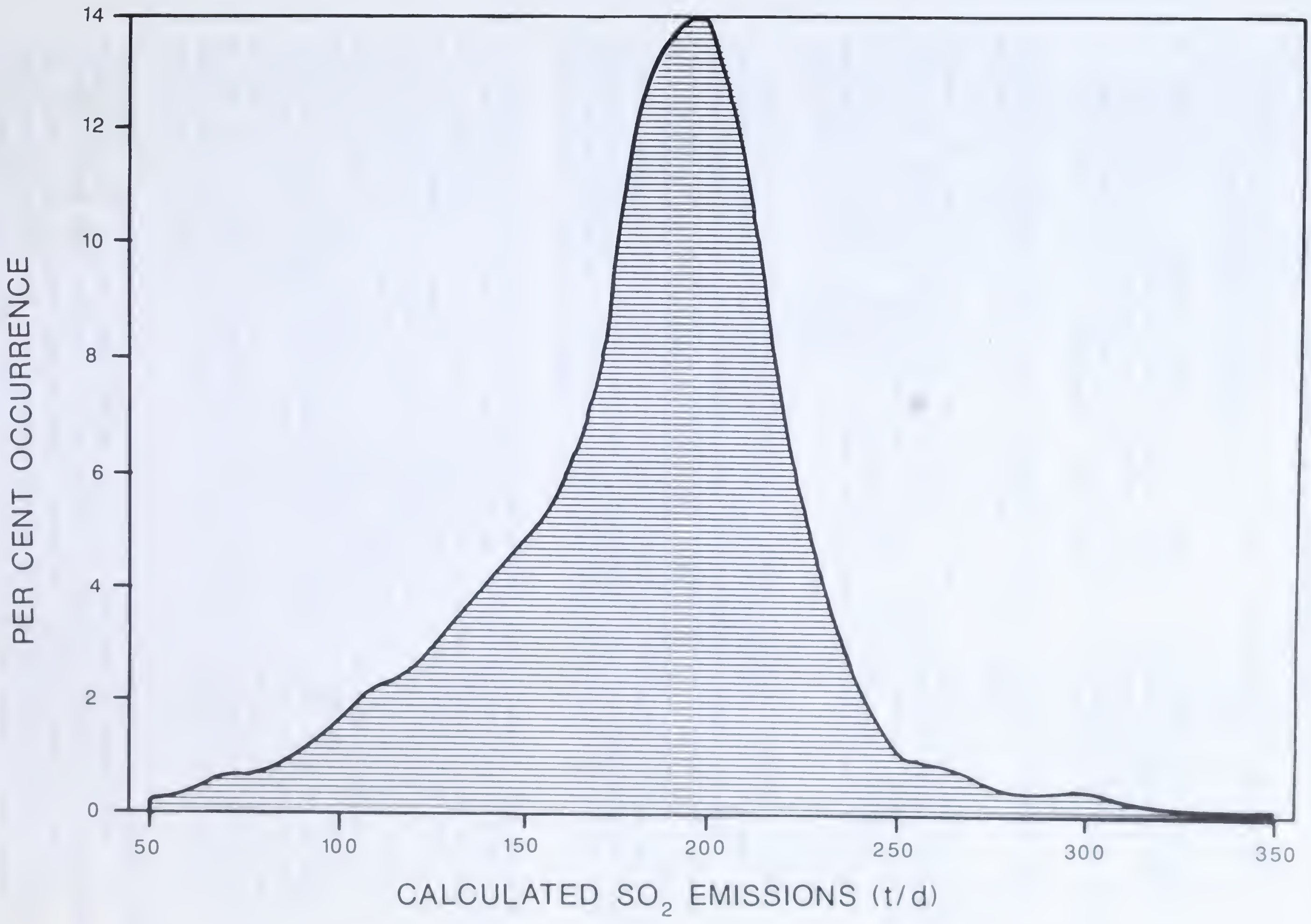

FIGURE 4: FREQUENCY DISTRIBUTION OF SO_2 EMMISSION RATES FROM SYNCRUDE FACILITIES FOLLOWING EXPANSION

(REPRODUCED FROM SYNCRUDE APPLICATION)

(ii) serious risk of damage to existing equipment and the resulting lower service factor, including a serious concern regarding the potential for implosion of a CO-boiler; and

(iii) lowered CO-boiler service factors resulting in increased requirement for diversion.

- The sulphur recovery level of the proposed operation is increased over the recovery of the existing plant. This is a consequence of the technology selection of hydrocracking upstream of coking. Environmental considerations, as well as the economic driving force of product yield, influenced this choice of technology.

Syncrude requested that A.Env. adopt the 90-day rolling average SO_2 emissions limit in place of the current 24-hour limit.

A.Env. did not feel that it was appropriate to replace the daily limit with the 90-day rolling average limit. It believes that the proposed limit of 265 t/d of SO_2 based on a 90-day rolling average period is for a different purpose than the existing 292 t/d of SO_2 on a 24-hour averaging period. Further, A.Env. still sees the need for a 1-hour limit and a 24-hour limit.

At the Band's request, flared emissions from the Syncrude plant were reviewed. This review showed that SO_2 emissions from flaring had reduced from 28.2 t/d in 1983 to 2.0 t/d in 1986. While it was recognized that this was a significant reduction in flared emissions, it was suggested that the ERCB and Syncrude, in conjunction with A.Env., further examine flared emissions at Syncrude, especially those which may cause contravention of ambient air standards. It was recommended that this examination be carried out through the Regional Air Quality Coordinating Committee (RAQCC).

In response to questions from the Band about the validity of Syncrude SO_2 emissions claims, the Syncrude Expansion Emissions Technology Study was undertaken. This study confirms that SO_2 emissions would be reduced in the proposed expansion. The study further concludes that the application of flue gas desulphurization (FGD) to the fluid coker/CO-boiler flue gas could reduce SO_2 emissions to 25 t/d. The SEETS consultant noted that, although FGD could be installed at Syncrude, the safe design and operation of such a system is not a trivial engineering problem and would be costly. The cost of sulphur capture, on the basis of a very preliminary analysis, was estimated to exceed $1280 per tonne or from $3.00 to $3.25 per cubic metre ($0.48 to $0.52 per barrel) of synthetic crude oil production before amortization and from $1.13 to $1.95 per cubic metre ($0.18 to $0.31 per barrel) after amortization.

The SEETS consultant agreed with Syncrude that "there is certainly some risk involved in the installation of FGD. Whether it should be characterized as "serious" is not quite so clear. There is no question but that such an installation would require a highly sophisticated engineering study and design to minimize any potential problems. Much effort would have to be expended on mechanical and control and safety

systems design. It is not believed that such problems are insurmountable, although the writer has no notion of what the cost might be."

In response to questions on how it would reduce SO_2 emissions should more stringent environmental standards be applied, Syncrude advised that the existing plant was designed and based upon a dry hot flue gas system with no provision for FGD. In any event Syncrude stated that SO_2 emission reduction was not warranted.

7.1.1.1 Band Position on SO_2 and Heavy Metals Emissions Reduction

"A. Current Lack of Data Base Regarding Sulphate Deposition

The Band noted that at present the permitted SO_2 emission limits of the operations in the region are not based on regional acid deposition target loading levels or projected short- or long-term impacts of these emission levels on the waters or soils in the region but rather are based on source standards arising from an assessment of the capacity of the emissions reduction technology of the plants at the time of fixing plant design.

After 20 years of plant operations with total regional licensed SO_2 emissions exceeding 600 t/d and actual emissions exceeding 400 t/d, acceptable and safe target loading levels of acidic depositions for lakes and soils in the region are still not defined. Such targets are apparently being prepared by a Western and Northern Canada Technical Committee including federal and provincial government representatives but such information would not be available until late in 1988 or 1989. No research leading to regional specific target loading levels is under way.

The Band also noted that there appears to be uncertainty regarding the projected total level of sulphate currently deposited in the region. Both wet and dry deposition have to be registered in order to accurately reflect the total sulphate deposition in the region. The actual rates for dry deposition are not well understood and have not been measured by A.Env. or the operators in the region. Syncrude has projected deposition rates using a computer model. The Band recommended that further field data on wet and dry deposition be obtained to allow refinement of computer modelling.

The Band requested assurance from A.Env. that, as a regulatory agency operating by professional standards, it is satisfied with the information provided by Syncrude on the actual current level of wet sulphate deposition in the region, its projections on total sulphate depositions, the method by which both were calculated, and the accuracy of the Syncrude computer model.

B. Lack of Data on Deposition Impacts

The Band noted that at present there exist no baseline data or research information to determine whether the existing combined

levels of wet and dry acid deposition are affecting the lakes and soils in the region. At present there appear to be no observable detrimental impacts but such impacts usually only appear after a threshold point is passed. Damage is then usually irreparable. No projection or forecasts on the impacts of the current level of deposition on lakes or soils were provided. The Band is advised that the technology and methodology are available to make such projections or at least "educated predictions" from which target loading levels can be set.

Given the lack of data on acid deposition rates, target loading levels, and impacts of SO_2 emissions on aquatic and terrestrial life, the Band concludes and Syncrude concurs that both the short- and long-term effects of the current regional levels of SO_2 emissions are not well understood. The EIA from Syncrude also indicated that "the effects of sulphate deposition on terrestrial and aquatic ecosystems in the region are subtle and remain poorly understood."

It was the Band's position that research regarding the actual current level of acid-forming emissions and heavy metals deposition in the region and its short- and long-term impacts on lakes, soils, and health of animals and persons in the area is a matter requiring further research. Research is required to establish an annual target loading level for total sulphate deposition in the region. The resultant information should then be used in the determination of licences and approvals governing SO_2 emission rates.

It was recommended that all further research regarding SO_2 deposition, actual and modelled, and the current and projected effects on the soil and water arising therefrom should be discussed and co-ordinated through the RAQCC.

C. Regional Airshed Management

The Band concurs with the following comments from The Review Panel on Environmental Law Enforcement (p.14):

"Attention should be given to the development of an airshed management concept which specifically recognizes areas for enhanced protection and areas of large concentrations of industrial or other emission sources. This airshed bubble concept has been successfully applied elsewhere...".

It is the Band's position that the ERCB and A.Env. should consider the total regional impacts of heavy metals and sulphur deposition, both current and projected, in setting emission limits and technology requirements for operations. By establishing acceptable regional deposition rates, it would then be possible to establish maximum total allowable emissions which may not be exceeded in total by all operations in the region. All future and existing operations should be required to operate within regional deposition limits. This may require new operations to have costly emissions control technology installed or necessitate the retrofitting of the Suncor

and Syncrude plants to reduce emissions to accommodate additional operators in the region.

Since an increase in industrial operations in the region is expected, the Band believes a regional approach to setting individual operations' limits must be established. This is particularly important in light of the Band's position that the ERCB and A.Env. should adopt the "low-risk approach" to sulphate and heavy metals deposition, that is, adopting policies and standards which minimize unforeseen future negative impacts of emissions by erring on the side of caution in requiring lower levels of emissions from all current and future operators. Consequently, the Band believes the ERCB and A.Env. should use opportunities afforded by plant expansions to revise approval and licence conditions to reduce the permitted levels of emissions of the current operations. This would make room within the regional airshed for additional emissions from future operations. The Band considers the Syncrude CAP to be a valuable first step in overall reduction of emissions from the oil sands plants.

D. Emission Reduction Technology

The Band noted that, according to the SEETS consultant, the installation of FGD would lower SO_2 emissions by 90 per cent (from 230 to 25 t/d). Over the next 30 years this amounts to a reduction of approximately 2.5 million tonnes SO_2. It would also eliminate the emission of most of the larger, heavy metals bearing (lead, vanadium, nickel) particulates. This could be achieved for an estimated cost of $0.18/barrel, about 1 per cent of the current Syncrude crude oil market price, after a 7-year amortization period. The Band noted that FGD is the best technology available today for SO_2 and heavy metals emissions control.

In light of the A.Env. policy of requiring the installation of the best practicable pollution control technology, the Band stated that the onus clearly lies on Syncrude to demonstrate conclusively to A.Env. and the ERCB that FGD is not technically achievable and operationally acceptable. The Band acknowledged Syncrude's view that the installation and operation of FGD could create substantial risk of interference with the existing operations, possibly leading to shut-downs, additional flaring, other damage to equipment, and large amounts of residual wastes on site. However, in the Band's view, both A.Env. and the ERCB must be conclusively satisfied, before deciding not to require FGD, that, in light of their thorough review of the technology and Syncrude's objections (given the substantial technical and engineering capacity of Syncrude), these problems cannot be resolved in a satisfactory manner. The Band noted that it does not have the resources or capacity to comment further on the engineering or technical aspects of this issue. In any event, the ERCB approval should require that the Syncrude expansion should not make more difficult the future retrofitting of emissions control technology.

The Band stated that minimizing risks to the operation and the environment is beneficial to all Albertans and Canadians. The Band stated that, regardless of the decision of A.Env. or the ERCB on requiring FGD, Syncrude should be given appropriate regulatory and financial incentives to design the best available and achievable technology to reduce emissions of SO_2 and heavy metals and to install it in a manner that does not put the operation of the plant at risk. The Band suggested that Canada and Alberta should provide Syncrude with grants or tax and royalty incentives to conduct further research and testing on the installation of FGD or other emission control technologies. The Band noted that the Minister of Environment Canada has clearly stated that capital costs for major pollution control initiatives would be considered for relief through federal pollution abatement programs.

In the opinion of the Band, the design and engineering research undertaken by Syncrude on the installation of FGD or other technologies would be of benefit to all operations, both current and projected, in the area. It may also have further implications for the petroleum industry in Alberta and could represent a major initiative.

The Band suggested that an approach modelled after AOSTRA, whereby the development of new oil sands technology is cost shared, may be appropriately adapted for the development and testing of new technology for SO_2 emissions reduction that may be marketed both nationally and internationally. Another approach would be for government regulatory agencies to establish progressively more rigorous standards for sulphur removal for future expansions of new plants, which would allow industry to select and adapt technologies to meet these new requirements.

E. Band Summary and Recommendations

1. The Band notes the lack of conclusive research on regional acid deposition rates, target loadings, and impacts of SO_2 and heavy metals emissions on aquatic and terrestrial life, and in general the lack of relevant data which could be used as a guideline in establishing permitted source emissions for regional operators. The Band would, therefore, urge the RAQCC to promote the undertaking of all necessary research relevant to these issues.

2. The Band proposed that A.Env. and the ERCB co-operate with industry in establishing a regional target loading for current and future levels of SO_2 and heavy metals deposition. The development of an airshed management concept which specifically recognizes areas of large concentration of industrial air emissions would give rise to alternative approaches to research, licensing, and monitoring within this region.

3. The Band stated that A.Env. and the ERCB, in setting licence and operating standards for emissions, must include a reasonable provision for future growth of emission sources within the region. Consequently, the Band believes an orderly incremental phase-in of

new technologies, at existing and new plants, to reduce total regional emissions should be required by A.Env. and the ERCB when setting approval and licence conditions. The Syncrude expansion should only be permitted to proceed in such a way that it would not make more difficult the future retrofitting of emissions control technology.

4. The Band concluded, following a review of the Hickey report and the comments of Syncrude, that the best available technology, namely FGD, appears to be neither technically nor financially acceptable and that further joint public and private sector research is required to develop and test new technologies.

It recommended that the ERCB co-ordinate a study with Syncrude, other companies, and A.Env. which would undertake a thorough review of the main technological options which are, or could be, implemented to reduce regional loadings of acidifying compounds and heavy metals.

5. The Band proposed that Alberta, Canada, and regional operators in the Fort McMurray area establish an agency modelled after AOSTRA to undertake research on the design, construction, and operation of new technologies to reduce heavy metals and SO_2 emissions."

7.1.1.2 SERG Conclusions on SO_2 Emissions

SERG agrees that, in the absence of definitive information on the environmental impacts of SO_2 and other (NO_x, particulate, and heavy metals) emissions, it is necessary to take all practical steps to minimize these emissions. This can be done in two ways: utilizing process plant technology which results in minimal SO_2 emissions (eg. hydrocracking) or cleaning up the SO_2 from processes which produce it in large amounts (eg. fluid coking). Syncrude in its proposed expansion chose the former which, in combination with a sulphur plant tail gas clean-up unit (Sulfreen), results in no increase in SO_2 emissions despite a 90 per cent increase in synthetic crude oil production.

SERG, however, believes it prudent not only to not increase SO_2 and other emissions but also to actively pursue means to reduce them. The SEETS consultant stated that FGD is technically feasible, but is expensive and could put portions of the Syncrude operation at risk. SERG believes that further study of the options available for upgrading bitumen and/or reducing SO_2 emissions from oil sands processing plants is warranted. Such studies should include an analysis of cost, hydrocarbon yield, and environmental impact along with the ability of these technologies to be retrofitted to existing operations. SERG participants believe that the onus is on the emittors and appropriate government agencies to do this analysis and to include where necessary the conduct of necessary pilot and prototype demonstration programs. The results should be reported to the ERCB and A.Env. in a timely fashion.

7.1.2 Sulphur Recovery

Syncrude proposed to install a new 700 t/d 2-stage Claus sulphur recovery unit. Tail gas from this new unit would be processed in the Sulfreen unit to achieve a 98 per cent minimum quarterly average sulphur recovery. Syncrude noted that the addition of this sulphur plant would result in 600 t/d of spare sulphur recovery capacity following expansion and would allow Syncrude to maintain full production even during a maintenance shutdown of one of the two existing 550 t/d sulphur plants without flaring acid gas. Shut-down of one of the two 700 t/d units (one existing and one proposed) would require some curtailment of operations. Syncrude indicated that its sulphur recovery system, that is, a Sulfreen plant in combination with four sulphur plants, is designed to recover in excess of 99 per cent of the sulphur contained in the acid gas feed and that 98 per cent quarterly average recovery is a suitable performance limit.

The potential for increased sulphur recovery, and the applicability of the ERCB/A.Env. guidelines on sulphur recovery for gas plants, was discussed at SERG meetings. The feasibility of increased sulphur recovery was also dealt with by the SEETS consultant.

Members of an A.Env./ERCB task force which recently prepared a report which reviews existing sulphur recovery guidelines and proposes new guidelines noted that its report had dealt with sulphur recovery at gas plants and the applicability of any new guidelines to other industries was not addressed. Task force members noted that, for gas industry sulphur plants of the scale proposed by Syncrude, recommended sulphur recovery would be in the range of 98.7 per cent to 99.5 per cent. It was noted that Syncrude had already invested in improved sulphur recovery during the capacity addition program and that the process installed had a design sulphur recovery of 99 per cent.

Syncrude noted that increased sulphur recovery would require replacement of the Sulfreen process. It argued that the proposed sulphur recovery guidelines should not apply to oil sands plants for reasons of upstream plant complexity and sulphur plant operability and reliability. Nonetheless it expects to come close to, if not exceed, the current sulphur recovery guidelines for gas plants.

The SEETS consultant reviewed the cost and feasibility of alternative tail gas clean-up processes and reported that the cost of sulphur capture with a high efficiency sulphur process (SCOT) was $688/t. He noted that this cost estimate was not of high quality and should be considered notional; it should provide some insight into the subject but would require reworking to today's construction situation for a rigorous appraisal.

SERG recommends that Syncrude's proposed sulphur recovery level be approved. This recommendation is based on the facts that sulphur recovery is expected to be within the range recommended by the sulphur recovery task force, the sulphur recovery guidelines do not now apply to oil sands plants, and the Sulfreen system is installed. Additionally,

the facilities upstream of the sulphur plant are complex and there is a need to ensure their reliability.

7.1.3 Particulate and Heavy Metals Emissions

Syncrude provided calculated emissions of vanadium, nickel, and particulates for the currently approved facility and for the proposed expansion. The proposed expansion is anticipated to result in a small reduction in levels of emission of vanadium, nickel, and particulates. This results from the demetalization of the bitumen occurring in the hydrocrackers, whereby metals are deposited on the hydrocracker catalyst, and a slight reduction in the amount of coke burned in the fluid cokers.

The SEETS consultant studied particulate and heavy metals emissions and concluded that particulate emission will be unchanged and the emission of nickel and vanadium will be reduced after expansion. He concluded that, with a confidence of 99 per cent, the maximum rates of particulates, vanadium, nickel, and lead are anticipated to be 5700 kg/d (0.1 grams per kilogram of flue gas), 4.6 kg/d (0.0001 grams per kilogram of flue gas), 1.5 kg/d and 0.7 kg/d respectively.

The Band expressed concern with regional heavy metals emissions and recommended that further work be done to measure metals emissions rates, to determine the impact of heavy metals on the environment, and to develop standards. The Band recognized Syncrude has made exceptional efforts to document levels of metals emissions from its plant and that ambient levels of most metals in the region are well below Ontario standards established for urban areas.

The Band did not accept that significantly elevated ambient levels of metals should be accepted in the Fort McMurray region, regardless of standards or emissions rates elsewhere in North America. It was the position of the Band that the ambient air quality of the Fort McKay region be protected. The Band stated that it has enjoyed exceptional air quality for generations and does not accept significant deteriorations in it. The Band believes that standards that may be set for heavy metals accumulation should take account of impact on the local environment. The Band noted a lichen monitoring network established by Syncrude in the 1970s has indicated an accumulation of heavy metals in the region. While the Band accepted that this is the only valid study in the area, and commended Syncrude for its commitment to continue such work, it recommended that encouragement and co-ordination of air quality research regarding heavy metals impact be maintained through the RAQCC.

The Band noted that at present there are no regulatory standards for heavy metals emissions other than those established for particulate emission per unit mass of total stack emissions. The Band stated that this standard may not be appropriate in light of the total regional emission of heavy metals from all sources over the long term. The Band and Syncrude were in agreement that a research program be continued and expanded to monitor and measure the effects of heavy metals and particulate emissions on the vegetation and animal life in the area. In addition, the Band considered that such studies should be extended to

include human health. It further recommended that the ERCB and A.Env. direct operators to undertake further research to examine whether other economically feasible engineering technologies are available to allow reduction of particulate and heavy metals emissions rates.

SERG is satisfied that the emissions of particulates and heavy metals would not increase as a result of the proposed expansion and in fact may decrease. While there is no evidence of significant environmental impact from particulates and heavy metals at this time, SERG endorses the proposal that the operators in the area pursue research on potential environmental impacts and feasibility of technology to reduce emissions. The RAQCC is a suitable vehicle for co-ordination of the impact studies. The results of such studies will allow the regulatory agencies to determine the appropriate direction to operators.

7.1.4 Hydrocarbon and Fugitive Emissions

Syncrude proposed to design its new extraction facilities to meet or exceed levels of bitumen and naphtha recovery attained in the existing plant. Additional tankage required would have floating roofs to minimize hydrocarbon emissions to the atmosphere. A new low-pressure smokeless hydrocarbon flare is proposed to handle upset releases from the expanded facilities. An auxiliary flare stack would handle excess flare loads resulting from major plant contingencies. Sizing of the stack and the main flare header would be based on worst overall contingency relief situations.

In response to Band requests to consider the application of research and development improvements in the area of bitumen and naphtha lost in tailings streams, Syncrude noted that it has undertaken such work and installed systems since 1984. A naphtha recovery system now installed recovers 70 per cent of the naphtha previously lost to tailings. The Band recognized that Syncrude has made a major advance in hydrocarbon control by reducing naphtha losses to the tailings pond. The naphtha recovery unit developed by Syncrude was acknowledged to represent the state-of-the-art. Additionally, Syncrude noted that the recovered oil (naphtha) is that which is most likely to float on the pond and thus cause odour or atmospheric emission impacts.

In response to questions from A.Env., Syncrude described its fugitive emission control program and associated plant modifications designed to deal with H_2S and hydrocarbon fugitive emissions. Hydrocarbon control modifications include, besides the naphtha recovery and tailings oil recovery units noted above, improved vapour recovery systems and improvements to hydrocarbon flare stacks and tankage.

Syncrude's fugitive emission program attempted to identify all potential sources of atmospheric contamination by hydrogen sulphide at its project site. Syncrude then attempted to systematically eliminate these sources where practical to do so. As a result of the fugitive emission control program the following modifications were made:

- modifications to reduce leakage in diverter stacks,
- replacement of the H_2S flare tip to improve combustion efficiency,
- installation of improved process sensors in each plant which route gas to the H_2S flare system to ensure sufficient natural gas is added to combust H_2S,
- installation of a state-of-the-art igniter system on the H_2S flare system,
- construction of new sulphur pit roofs, and
- improved nitrogen blanketing on tankage.

Syncrude was satisfied that its fugitive emissions program has been successful and that the success is demonstrated by a reduction in frequency of occurrence of H_2S concentrations above the Alberta ambient air quality standard. This program is continuing and has been expanded to allow consideration of hydrocarbon emissions. An extensive oil loss survey was conducted in 1986/87 and the thrust of ongoing work is elimination of hydrocarbon losses.

Syncrude and the Band concluded that, since insufficient data presently exist concerning hydrocarbon emissions in the region, it is presently not practical to undertake a proper evaluation of concerns with hydrocarbon emissions. The Band noted that there is no monitoring system in place which is capable of analysing the character, quality, and quantity of hydrocarbon emissions at the plant site or in Fort McKay.

Although the existing monitoring site at Fort McKay measures levels of hydrocarbons, it does not distinguish the character or quality of these emissions. Initial data on hydrocarbon monitoring indicate that fumigations are occurring at levels which may be harmful, or which represent a significant nuisance, to community members. The Band suspects that this problem exists also for the community of Fort McMurray. This appears to be particularly true during times of significant valley inversions, or cross-wind shears, which may cause hydrocarbon concentrations to exceed the monitoring capacity of the available equipment in Fort McKay. Information on the toxicity of atmospheric pollutants suggests to the Band that there may be significant impacts on human, animal, and plant communities.

The Band and Syncrude recommended that the issue of hydrocarbon emissions be pursued through the RAQCC and this committee should have the following objectives:

- to establish a monitoring protocol for these emissions as soon as possible,
- to establish immediately thereafter a monitoring network for these emissions in the region, and

- to review and recommend that the companies take actions to minimize or eliminate noxious emissions to the atmosphere.

The Band stated that in addition to the above, a review of possible new enforcement standards and regulations for hydrocarbon emissions should be established as soon as possible. The overall intent of this initiative would be to establish the sources of hydrocarbon emissions in the region and to reduce these components from the regional airshed.

The Band and Syncrude agreed that studies are required to examine the rates and routes of dispersion of hydrocarbon emissions, including evaporation and indirect emissions, for the region. This initiative should be accompanied by establishment of a simulation model which indicates the movement and deposition of hydrocarbon in the vicinity of Fort McKay under a wide variety of atmospheric conditions which are known to occur.

The Band estimated that approximately 400 000 cubic metres of naphtha are disposed of into the Suncor and Syncrude tailings ponds annually, and it suggested that these may be major sources of hydrocarbon emissions. The Band recognized that Syncrude has made a major advance in minimizing naphtha losses to the tailings ponds through the installation of a naphtha recovery unit. The Band recommended that studies on operational methodologies for disposal of hydrocarbons during normal and upset conditions should be carefully examined by the ERCB and A.Env. with the assistance of the RAQCC.

SERG notes that activities currently under way by Syncrude, the ERCB, A.Env., and the RAQCC are dealing effectively with most of the concerns raised in this section. The ERCB should actively assist A.Env. in ensuring that the necessary work towards monitoring of hydrocarbon emissions is done and that regulatory standards are established.

7.2 Impacts from Air Emissions

7.2.1 Ambient Impact

Syncrude had maintained the position that its proposed plant expansion would not lead to exceedances of the 265 t/d 90-day rolling average SO_2 emission limit. Syncrude further stated that the estimated maximum number of hourly-averaged SO_2 concentrations greater than the A.Env. 1-hour standard (0.17 ppm) attributable to Syncrude emissions would be 4 hours per year and the highest predicted concentration would be 0.24 ppm. Given this, Syncrude has no plans to expand its existing air quality monitoring program. However, it recognized that such monitoring requirements are determined by A.Env. and are changed from time to time when necessary.

A.Env. stated that a very small number of exceedances are expected because of the random nature of atmospheric diffusion. The stack design, however, must anticipate no exceedances, on average, for any of the various combinations of conditions examined in the A.Env. Screening Model.

The Frequency Distribution Model yields a small number of exceedances because it searches over a much larger number of possible diffusion conditions. (In other words, it picks up some of the scatter about the average used by the Screening Model.)

The Band's position was that the Syncrude plant should be operated such that no exceedances of approved standards occur at any of the monitoring stations. Though the Band acknowledged Syncrude's significant corrective actions and improvements to the plant since 1982, which resulted in significant reductions in exceedances of ambient air standards at the monitoring sites, any exceedance of regulated levels would be unacceptable to the Band. The Band would like to examine options to better manage the air quality of the region with respect to both air monitoring and total plant emissions. The Band suggested, and Syncrude agreed, that this question be more specifically addressed through the RAQCC or another regional air quality review agency. The Band understands that the RAQCC will not have any regulatory authority or responsibility.

The Band stated that there presently are questions about the suitability of the locations of some air monitoring stations in the oil sands region, and therefore it had reasons to doubt results from the existing air quality monitoring network. While Syncrude currently operates their air monitoring network consistent with the requirements of A.Env., the Band suggested that a comprehensive review of the adequacy and nature of these and other industry or government facilities be undertaken by RAQCC. In the Band's view, there is a specific need for enhanced monitoring capability in and around Fort McKay.

SERG agrees that a review of the monitoring network should proceed under the direction of A.Env., and that the RAQCC should be involved in co-ordinating the input by the various interested parties.

7.2.2 Acid Deposition

The Band's position on acid deposition is set out in Section 7.1.1.

A.Env. stated that the available information indicates that current deposition rates of acidifying substance has not resulted in any observable effect on the oil sands region. However, A.Env. must continue its research and monitoring work in the area in order to determine what level of acid deposition would have an effect, and whether or not the present emission limits are providing adequate long-term protection to the region's soils, surface water, and vegetation. A.Env. stated that there is adequate time to determine the level at which impact would occur and to take corrective action if required.

A.Env. advised that it will shortly release a report which identifies areas sensitive to acid deposition effects on soils, geology, and aquatics. It is also working with the federal, North West Territories, and other western provincial governments to establish interim target loading levels for protecting sensitive ecosystems from acid deposition in western and northern Canada.

AFL&W had concerns with additional sulphate deposition from the Syncrude plant expansion and its effect on trees and plant life. However, it was satisfied with Syncrude's claim that no increase in emissions would result from the proposed expansion.

SERG agrees that even though the present emission levels of acid-forming emissions are not having an observable impact on the region, studies which help to better understand, predict, or control acid deposition must be considered a high priority.

7.3 Water Management, Tailings Impoundment, and Ground-water Concerns

The proposed expansion would increase the use of raw water from the Athabasca River by some 25 per cent owing to higher production rates. However, Syncrude would remain within the water diversion limit of 61.7 million cubic metres per year as currently approved under the Water Resources Act.

Syncrude proposed to begin disposal of tailings sand outside of the tailings pond in the year 1990 and to utilize the existing tailings pond only for sludge and water storage. The disposal of sand outside the tailings pond would be a "dry" storage with water and sludge returned to the tailings pond. The sand disposal area would not be designed for storage of water or sludge. Instead, runoff from sand disposal area beaching operations would be pumped into the existing tailings pond for settlement and clarification of recycle water.

Syncrude's plan for the tailings envisaged sludge and water stored in mined-out pits and behind land masses with no long-term storage of tailings sludge in the existing out-of-pit tailings pond. In the interim the tailings pond would remain a settlement area as volumes of sludge are transferred to mined-out areas. At present, this pond contains excess volumes of clarified water and Syncrude is examining methods of reducing the accumulation of water.

Syncrude has a ground-water monitoring network around the existing tailings pond and proposed to establish a similar network around the proposed tailings sand disposal area in order to monitor ground-water quality in these areas.

In a report to the ERCB in May 1986 from a similar application review group dealing with an earlier modification of Syncrude's facilities, the following statement of the Band's position on this matter is made:

> The Band "questions the philosophy and continued practice of a total containment strategy, as this would appear to potentially worsen hydrogeological concerns for the tailings pond over time. Instead, parallel treatment and disposal strategies should be reviewed to hasten, or reduce the volume of contained tailings water in conjunction with a wider review of tailings management practices at the site."

SERG agrees that in the long term it is desirable to minimize the accumulation of tailings water. The Band confirmed, however, that any discharge of contaminated tailings pond water at this time would be unacceptable to it.

It was agreed that Syncrude would involve the Band should significant alternatives be contemplated regarding site-water management. Any such review of site-water management, if required, should be led by appropriate Alberta Government agencies to ensure that sound long-term environmental management practices in regard to the routing of runoff streams to and from the tailings pond are well understood and carefully examined. Fort McKay would be consulted during such review.

The potential for tailings pond water seepage was discussed and available information reviewed. Following this discussion, the SERG participants were satisfied that there does not appear to be a significant danger of contamination of ground-water aquifers from the project. Nonetheless, it was agreed that continued monitoring programs are required and would be carried out.

7.4 Reclamation

Syncrude filed a conceptual reclamation plan describing the development sequence for the period 1988-2018. This plan differs from those previously approved in that long-term storage of the tailings sludge in the existing out-of-pit tailings pond would be avoided. The current plan envisages tailings sludge and water storage in the mined-out area and behind large land masses. This would result in sludge ultimately being contained in a stable, maintenance-free area as opposed to being stored behind sand dikes. However, storage of sludge in-pit requires displacement of sand and overburden outside the mine pit in order that sufficient volume exists for the sludge. Thus, out-of-pit sand and overburden storage is required.

The reclamation plan would also be changed by the addition of the East Mine area. There, mining would start at the escarpment and advance westward. Overburden material would be hauled to the flats below the escarpment and would gradually build upward and westward in the mined-out pit as the oil sands mining face advances.

The base elevation of the proposed discard site on the river flats is above the river level expected during 1-in-100-year floods on the upstream portions of the site and at the 1-in-100-year flood level on the downstream portions. Thus, even during such a flood event, the dump should not be subject to serious erosion by the river currents. Additionally, Syncrude noted that natural river silt levels in a 1-in-100-year flood would be very high and the contribution of erosion from the proposed overburden dump to river silt loadings would be insignificant.

Although Syncrude's application described operations only until the year 2018, the mineable ore in the vicinity would not be exhausted by then, and it likely would continue mining beyond that time. However, if a

decision were taken that mining should cease at the end of the applied-for life the following actions were envisaged by Syncrude:

- All sludge would be stored within the completed landscape behind overburden and tailings sand land masses and natural topography.

- The disturbed area on the east side of the Base Mine, shown on the reclamation diagram for year-end 2018, would be filled to grade with overburden from the East Mine area and reclaimed. Thus, the East Mine overburden disposal area would be somewhat smaller than indicated for year-end 2018.

- Reclamation would be completed on the southwest sand disposal area and on the bottom of the out-of-pit tailings pond.

- The remaining East and North Mine pits would be reclaimed as water bodies following appropriate sloping of highwalls.

Syncrude advised that its soil reclamation and surface preparation techniques would be as described in the reclamation plan filed with A.Env. in 1984. However, it noted that research continues on alternative reclamation technologies, and techniques may change should more successful or cost-effective methods be proven. Syncrude's objective would be to restore 80 per cent of the land to forest cover. It proposes that sand disposal areas would be reforested predominantly with jackpine and aspen while overburden areas would be reforested with white spruce and aspen. The Band has expressed an interest in some of the reclaimed areas being available for wildlife and has requested that a balance between reforestation and other land uses be ensured. A.Env. invited the Band's participation in the Development and Reclamation Review Committee (D&RRC) review process.

SERG agrees that alternative reclamation and regional land use strategies are possible. SERG participants agree that the Band should table its concerns on possible integrative options in reclamation planning to the D&RRC.

8 SOCIOECONOMIC MATTERS

8.1 Band View of Socioeconomic Impacts of Resource Development

"The socio-economic impacts of resource development on Fort McKay have been well documented in previous studies on and by the community. These include a report entitled, "From Where We Stand", prepared in 1982 and as well frequent correspondence and reports from the Band to government agencies on a variety of socio-economic and developmental issues.

Chief Boucher emphasized to SERG that historically Band members had been self-sufficient -- relying on hunting, fishing, and trapping, and "living off the land" in a manner that enabled families and communities to remain independent of government. He noted that it is the widely held view of Band members that, with the advent of major

resource developments and accompanying increased hunting and trapping pressure and associated environmental impacts, there has been a substantial decline in the population of game and correspondingly, the ability of residents of Fort McKay to sustain a traditional lifestyle, independent of government support and participation in resource development.

As a consequence, today the direct and indirect income from traditional harvesting by members of the community is substantially reduced; there has been a decline among members pursuing traditional hunting, fishing, and trapping activities; a loss of these skills amongst the younger generation, and an increasing dependence on government assistance and employment in the resource development sector. This transition and forced adaptation to incompatible lifestyles has resulted in considerable stress in the community, breakdown of families and community networks, social problems and increased alcoholism, and a movement away from the traditional values, lifestyle, and economy of the community.

The Band has had little meaningful support in coping with these changes and making the transition. As recently as 1985, the community lacked proper housing, infrastructure, community cultural and recreational activities in the community, and proper basic services, such as roads, power, gas, etc. Only today are these needs slowly being met.

Moreover, the level of income in Fort McKay was one third that of that in Fort McMurray, while immediately adjacent to the community over $2.5 billion annually in revenue was generated for industries and government. For years much of Fort McKay lived in poverty and still lags in income far behind the non-native community. This disparity only aggravates the perception of the residents of Fort McKay that they unwillingly bear the negative impacts of development which has substantially benefitted the corporate sector, residents of other towns and Canada and Alberta.

As well, the Chief, on behalf of the Band, is concerned about the undermining of the Treaty and Aboriginal rights of the Band. While promises and good intentions were expressed in Treaty 8 that would assure Indian people of retaining a hunting, fishing, and trapping economy or proper compensation for loss thereof, neither the private sector nor either level of government have within their intent or legislation proper mechanisms to compensate for loss of hunting, fishing, and trapping rights, or more specifically loss of access to those activities and the social, cultural, and economic benefits they provided to the community.

The Trapper Compensation Policy has proven ineffective and inadequate; it provides no compensation for loss of lifestyle, loss of benefits such as income in kind, food, etc. Neither the companies nor governments recognize or compensate for the loss of real and intangible results derived from pursuit of a traditional lifestyle.

In 1981, Fort McKay developed a strategy called "Parallel Development". This model set out a proposal for retaining the strong and essential elements of the traditional culture and lifestyle while more effectively integrating and adapting the community to the current realities of resource development. The Band is still in the process of trying to implement this process and educate both government and the private sector about the real difficulties and realities facing the community in making this transition.

Until 1985 and the commencement of the Interface Committee, SERG, and expanded government response on this to the community, which the Band views as positive and progressive steps, there had been no proper forums or mechanisms for dialogue between Fort McKay and the public and private sectors. Consequently, the Band is still "feeling its way" in developing mechanisms for effectively communicating with those sectors and dealing with their impact on Fort McKay. It is expected that this will require a number of years and an ongoing structure and process to make an accommodation or transition to the ongoing impacts of resource development.

In the meantime, the Band will struggle to preserve its options to pursue a traditional lifestyle and culture, take whatever measures are necessary to preserve and protect the environment that supports this culture and lifestyle, and try to take full advantage of the benefits afforded by the public and private sector for the development of the community of Fort McKay in a manner compatible with community aspirations, culture, and values.

The Band reported a marked improvement in public and private sector response in the past several years. This is demonstrated by handling of applications for major project changes by review groups such as SERG and the increase in government and industry support of economic activity to the Band's benefit. Particular achievements noted were:

- construction projects in Fort McKay such as the multi-purpose Band office and recreational facility, a water and sewer system, and a firehall,

- development of the Northern Environment Education Program -- a unique program which would be used throughout the provincial education system,

- agreement with Government on a reserve at Fort McKay,

- other miscellaneous contracts from A.Env. (eg. community clean-up and firebreak), oil sands operators (OSLO, AOSTRA, Suncor, and Syncrude),

- funding support from Government and industry for expert advisers to the Band which facilitate its participation in committees specifically set up to assist the Band (the Interface Committee, the RAQCC, SERG, the Community Environmental Education Committee) and other regional forums (eg. Northern Alberta Development Council), and

- improvement in employment levels for community members."

8.2 Assessment of Socioeconomic Concerns Expressed by Fort McKay and Other Native Leaders

The Band reviewed the Socioeconomic Impact Assessment (SEIA) which accompanied the Syncrude application and identified to Syncrude areas of concern. Subsequently, Syncrude met with native leaders in the Mildred Lake area and documented matters of mutual interest and responsibility that needed to be resolved. Nichols Management Consultants, a Syncrude consultant on socioeconomic issues, prepared a report of understanding of issues of interest to the Band. The complete report is attached as Appendix C. A summary of the report is given in the following excerpt from Syncrude's deficiency response to the ERCB:

> "Subsequent to completion of the SEIA, the Syncrude expansion project team met with native leaders in the Mildred Lake region to document views on the anticipated impacts of the project and key socioeconomic barriers faced by native communities.
>
> Native leaders have expressed general observations regarding the local socioeconomic impacts of oil sands development and the actions required to improve native participation in relation to those resource projects.
>
> In general, it was felt that a variety of negative socioeconomic and environmental impacts have been experienced as a consequence of the resource developments nearby, but equivalent benefits have yet to be realized. The following barriers were identified as limiting native communities' abilities to participate fully in large-scale resource development projects:
>
> - Funding for Local Government and Administration
>
> It was generally held that the present financial arrangements under which native bands operate are unsatisfactory. For example, through the funding formula used by the Department of Indian and Northern Affairs (INAC), small bands such as Fort McKay are allotted budgets which are inadequate to maintain even a minimum administrative and Government structure and these budgets have declined over time in real terms due to federal spending restraints. The inadequacy of current funding arrangements is exacerbated by the extraordinary demands placed on the community by the resource-based growth and development which is occurring in the region. Until recently, the bands were able to access special funding through INAC's Resource Development Impact Program; those funds were available to the Band to deal with the particular development needs and pressures it faced. That program has now been discontinued and no longer represents a supplementary source of financial assistance to the community.
>
> The Bands have few alternative financial resources with which to supplement INAC funds.

Without sufficient financial resources, bands cannot maintain the management and administrative capacity to carry out required planning and development activities, and face ongoing problems in terms of recruiting and retaining competent staff. Wage and salary levels in the region are high and qualified staff tend to relocate to higher-paying positions with other employers. The demand placed on Band administrative manpower are excessive and compounds the relatively poor working conditions. A considerable amount of staff time is also taken by the need to identify and access various sources of external financial assistance.

In sum, the need to develop an adequate and stable funding base is seen as priority.

- Infrastructure and Facilities

The standard of community facilities available to native communities is generally low and has adverse effects both in terms of the social and cultural health and the general economic well-being of the communities.

- Programs and Services

A number of service delivery gaps or shortfalls have been identified which reduce the ability of native community residents to participate fully in new economic opportunities that arise in the area. Examples of these shortfalls include

- employment training,
- substance abuse counselling, and
- daycare facilities and programs.

- Business Development and Contracting

A number of concerns were expressed regarding contracting experiences with Syncrude. In the native leaders' view, the total value of contracts held by native community-based businesses is low, the contracted services provided are relatively low-skilled, and the contracts themselves -- which have been awarded on a negotiated basis -- offer little opportunity for profit.

It is believed that the native communities' contracting capabilities have improved dramatically over the past 2 years and that they are in a position to successfully carry out much larger and more diverse contracts, but that local firms have been offered limited opportunity to bid on such contracts.

The perception exists that Syncrude places almost all of its requirements for goods and services to tender and that the only way the native community realistically can secure sizable contracts with the firm is on some form of negotiated basis. It is felt that negotiated contracts can yield competitive terms and performance for Syncrude while at the same time providing developmental and native employment benefits. It has been suggested as well that the linkage

between the procurement and native development sections of the firm is not as strong as it might be and that native contracting experience has suffered as a result.

- Employment

It is generally felt that the proposed agreement between the Athabasca Native Development Corporation (ANDC), Syncrude, and the Federal and Provincial Governments will establish broad objectives for native training and employment but that the specific elements of a program to achieve those objectives should be documented.

It is felt that Syncrude should specify the policies and plans it will adopt to support the hiring, training, and advancement of natives, and the internal staffing and resources that will be assigned to these tasks. The Band would like the firm to develop and articulate a Native Equity Employment Plan which would state the proactive measures to be taken to achieve the firm's native employment objectives. It also felt that Syncrude should examine employment alternatives within the organization which would allow native people to work for the firm on a seasonal basis, while allowing them to pursue traditional hunting, fishing, and trapping pursuits during other periods.

There is also interest in understanding what initiatives Syncrude has taken in the context of current capital programs, and proposes to undertake in respect of the expansion project, to encourage its contractors to employ native people. Concern was expressed that no contractors engaged in the current Syncrude capacity addition project have recruited employees from Fort McKay, nor have community-based firms secured any contracts in relation to that capital program.

Continuing concerns exist regarding the taxation of Indians registered under Treaty 8 who are employed by Syncrude and other resource companies in the area. Native leaders feel that those employees should be exempted from taxation as guaranteed under the provisions of the Treaty.

- Projects Impacts

Many of the foregoing issues are of ongoing concern and not all are specifically addressed to the expansion project itself, although some may be exacerbated or reinforced if the project proceeds. However, very specific concerns exist involving security during project construction. It is perceived that the rural RCMP detachment, which is responsible for policing a very large geographic area, cannot provide 24-hour security, which is felt to be necessary to discourage intrusions. The concern exists that the necessary policing arrangements be in place during the project construction phase."

It was noted at SERG meetings that Syncrude is working closely with the Band to detail its specific concerns and to attempt to resolve this issue. The following are the specific areas of interest to the Band that need to be addressed by Syncrude:

- The Band requested Syncrude to state its policy relating to the future provision of community-based financial assistance to Fort McKay and assist the Band as required to access identified local improvements from senior levels of government.

- The Band requested Syncrude to award sizable negotiated contracts to the community-owned businesses, and to state specific policies and guidelines relating to native contracting. It also asked Syncrude to identify organizational structure and resources which Syncrude would devote to native procurement and to identify contracts which Syncrude would make available on a sole-source negotiated basis.

- The Band requested Syncrude to specify policies and plans related to the hiring, training, and advancement of natives within the organization and to develop a Native Equity Employment Plan with proactive measures to achieve Syncrude's native employment objectives. Syncrude was also asked to state initiatives to be taken to encourage contractors to employ natives.

Syncrude and the Band agreed that Syncrude's native hiring and development policy would be covered in a detailed plan which would be part of an ANDC Agreement. SERG supports these initiatives.

9 SERG AGREEMENTS

9.1 Introduction

In the SERG terms of reference it is stated that after completion of the review process, SERG would advise the Board of the concerns that had been resolved and the details of those still outstanding. The SERG meetings resulted in agreement that certain issues were resolvable by the group, while others were to be referred to either A.Env., the ERCB, the Fort McKay Interface Committee (FMIC), RAQCC, or the Land Conservation and Reclamation Council. The following sections deal with issues which were deferred to the other agencies, and those which were resolved by SERG.

9.2 Issues Agreed to by SERG

- The project area requested by Syncrude should be approved.

- The requested new mining areas, those being the North Mine expansion and the East Mine extension, are satisfactory. SERG also agrees that final mine pit and discard disposal limits, as well as the recovery of ore underneath discard dump NT1, should be handled through the ERCB annual mine plan approval process.

- Syncrude should obtain Board and A.Env. approval prior to construction of any out-of-pit overburden disposal sites associated with the proposed expansion activities.

- Should a mine or an overburden disposal area be required west of the MacKay River, applications to the ERCB and A.Env. respecting resource and environmental impacts should be required and would be subject to whatever review procedures the affected agencies deemed appropriate at the time. The Band should be consulted on the development option and any application for a river crossing.

- Syncrude should continue to study options for increasing tailings water recycle and minimizing tailings water and sludge accumulation.

- Syncrude should not start construction of any tailings sand disposal site until approval is obtained from the ERCB and A.Env.

- Syncrude's proposed sulphur recovery level should be approved.

- There does not appear to be a significant danger of contamination of ground-water aquifers, from the tailings pond or from mine drainage water, resulting from the project. Monitoring programs should be continued.

- The Band should table its suggestions on possible integrative options for forestry and wildlife habitat development in reclamation planning to the D&RRC.

9.3 Issues Deferred to the ERCB, A.Env. and AFL&W

- Establish regional target loadings for current and future levels of acid deposition and heavy metals deposition.

- Resolve AFL&W concerns over the loss of waterfowl and pike habitat at Horseshoe Lake.

9.4 Issues Deferred to the Fort McKay Interface Committee

- Undertake a research program to investigate the impact of atmospheric emissions on the regional ecosystem, especially the accumulation of metallic elements in the vegetation and food chain.

9.5 Issues Deferred to the RAQCC

- Ensure the undertaking of research on regional acid deposition rates, impacts of SO_2 and heavy metals and particulate emissions on aquatic and terrestrial life, and the development of target loadings and standards.

- Ensure that hydrocarbon emissions in the region are researched, that a monitoring protocol and a monitoring network are established, and that procedures are established which minimize or eliminate such emissions. As necessary, advise the regulators on enforcement of standards and regulations.

- Review adequacy, nature, and location of existing air monitoring network.

- Review flared emissions.

9.6 Issues Deferred to the Land Conservation and Reclamation Council

- Consider possibilities for integration of forest and wildlife reclamation objectives.

The SERG process achieved its goal of promoting dialogue and better understanding among the ERCB, the Band, Syncrude, and Government Departments. By resolving many concerns outside the context of a public hearing, the SERG process enhanced the quality of the application review.

SERG recommends that the application be granted without specific conditions except those that the ERCB may otherwise place. The SERG participants agree that the issues discussed, in our consultations held in the past 18 months, are resolved to the satisfaction of all concerned or have been adequately referred to other committees recently formed for further discussion, research and resolution.

The SERG participants believe that, for the people involved, the issues discussed were more thoroughly reviewed and analysed and better understood than they would have been at a public hearing.

R. G. Evans, P. Eng.
Chairman, Syncrude Expansion Review Group
Energy Resources Conservation Board

Mr. L. Brocke
Alberta Environment

Mr. J. Boucher
Chief
Fort McKay Indian Band

Mr. J. Lack, P. Eng.
Alberta Environment

Mr. J. Slavik
Legal Advisor
Fort McKay Indian Band

Mr. A. Hyndman, P. Eng.
Syncrude Canada Ltd.

Dr. R. Wallace
Environmental Advisor
Fort McKay Indian Band

Mr. D. Thompson
Syncrude Canada Ltd.

Mr. J. L. R. Bondy
Alberta Forestry, Lands
and Wildlife

Dr. R. N. Houlihan, P. Eng.
Energy Resources Conservation Board

Mr. B. D. Prasad, P. Eng.
Energy Resources Conservation Board

APPENDIX A

SYNCRUDE EXPANSION REVIEW GROUP (SERG)
Terms of Reference

1. A Syncrude Expansion Review Group (SERG) is established to consist of representatives from Syncrude, Alberta Environment (AE), Alberta Forestry, Lands and Wildlife (AFL&W), Fort McKay Community and ERCB. ERCB will chair the review group, and will record and disseminate its conclusions.

2. The purpose of the SERG is to deal with Syncrude's plans for an expansion of its Mildred Lake Oil Sands Project to increase mine and plant output from about 8×10^6 m^3/year (50 million barrels) of synthetic crude oil to about 12 or 13.5×10^6 m^3/year (75-85 million barrels), by:

   a. Consulting with Syncrude prior to the filing of the applications to identify significant issues of mutual interest and advise of problems, concerns or interests which might be dealt with in the applications,

   b. reviewing the applications after they are filed to obtain clarification, information and understanding, and to give consideration to all aspects of the proposal including:

      (i) energy resource conservation and economic, orderly and efficient development of the resource
      (ii) on-site environment protection, pollution control and the observance of safe practices
      (iii) regional and local environmental impacts (air, water, land use), and
      (iv) socio-economic impacts and the fulfillment of the public interest, including employment and business opportunities for local native residents.

   c. advising the ERCB, AE, and AFL&W of the proposed issues to be addressed, the general importance of them to the public interest and the proposed procedure for presentation of conclusions thereon for consideration by the afore-mentioned including the provision of an iterative process where the issue may exceed the authority of SERG to reach viable conclusions,

   d. documenting any agreements reached, supplementary information filed, concerns raised or assurances given,

   e. documenting any areas of concern in which no agreement has been reached, and

   f. recommending to the ERCB as to whether the Application should be approved, and what conditions, if any should be attached.

3. The objectives of the SERG are to maximize the co-operation and communication between the parties, maximize each party's satisfaction with the decision and outcome, and minimize the time and cost associated with the review and approval procedure.

4. The scope of SERG is to facilitate assessment and consultation on issues arising from the Syncrude Expansion set of applications. The ERCB and AE will consider conclusions of SERG as key part of information leading to decisions on disposition of the applications.

5. The ERCB will fund reasonable participation by the Fort McKay Community by paying for:

   a. Its lawyer, and his expenses,

   b. its environmental advisor and his expenses, and

   c. the expenses of the Chief of the Indian Band or his representative.

6. The SERG may deem it advisable to hire a consultant to advise it on technical aspects of the plant operations or equipment. If so, it will apply to the appropriate levels of the sponsoring agencies for agreement to fund the consultant study, and will not proceed to hire a consultant until proper authorization is received.

7. Regardless of the outcome of the discussions of the review group, the final decisions on the applications would have to be in conformance with the established legislation.

8. The review group process being discussed would also tie into the EIA process. Although overall control and final decision with regard to an EIA would continue to reside with the Minister of the Environment, the SERG would attempt to deal with and provide adequate information on EIA related isues. If successful, the process would result in all EIA related concerns being adequately and satisfactorily dealt with by Syncrude. It is clear and agreed to by all parties that any participation by the Department of the Environment in the review group could not be construed as fettering or compromising the independence of that Department or its Minister to decide on EIA matters. It was also agreed that it would be important to maintain flexibility rather than adopting rigid guidelines in this regard.

9. The review group is free to discuss not only matters of oil sands and environmental technology, but also economic and social aspects including those related to the natives' aspirations, lifestyle, etc.

10. If there is a lack of agreement on any items, each party is free to play its normal role with respect to outstanding issues.

11. There are no restrictions on those items which might be discussed by the committee, but only directly relevant items will be documented whereas other items might be subject to informal and undocumented agreements or formalized agreements outside of the review process.

12. The initial basis for discussion for the SERG is a "Draft Preliminary Outline" of the application, to be provided by Syncrude in September 1986.

APPENDIX B

SUMMARY OF BIOPHYSICAL CONCERNS REGARDING

THE SYNCRUDE/ERCB APPLICATION

Drafted and agreed to by representatives of Syncrude and the Fort McKay Band September 1987.

1. Mining North of the Tailings Pond

In the Band's letter of June 26, 1987 the Fort McKay Indian Band requested the following from Syncrude:

> "... a comprehensive explanation from Syncrude of the intended use of the area between the tailings ponds and the community of Fort McKay. They also want firm assurances from Syncrude and the ERCB that there will be no mining north of the tailings pond and in the eastern section of lease 22."

Syncrude is not prepared to provide assurances that there will never be activity north of the tailings pond or in the eastern section of Lease 22. This means that future developments may come from within 3 km if not closer to the community of Fort McKay. The community of Fort McKay remains concerned about dust and noise from the potential mining operations in this area or from the disposal area if it is extended to the northern limits.

Some understanding or planning basis will be required between the community, ERCB, and Syncrude prior to developments which may result in significant nuisance impacts in Ft. McKay.

2. Expansion West of the McKay River

The Band is satisfied with the explanation received from Syncrude that, should an overburden disposal area west of the McKay River be required, a bridge or conveyor facility to transport overburden across the river could be designed so as to ensure that split material would not enter the river.

The Band would request that the ERCB phrase any approval so as to adequately plan for this potential development option and consult with the Band on any approvals for a river crossing of the McKay River which may be required.

3. Violations of Hourly SO_2 and H_2S Standards at Syncrude Monitoring Sites

As noted in the Band's letter of June 26th, the Fort McKay Indian Band is of the position that the plant should be operated such that exceedances of approved standards should not occur at any of the monitoring stations. While the Band acknowledges Syncrude's significant corrective actions and improvements to the plant since 1982, which have resulted in significantly improved trends with respect to air quality at the monitoring sites, any exceedance of regulated levels are unacceptable to the Band. The Band would like to examine options to better manage the air quality of the region with respect to both air monitoring and total plant emissions. The Band has suggested, and Syncrude agrees, that this question be more specifically addressed through the proposed Regional Air Quality Co-ordinating Committee or another regional air quality review agency. The Band understands that the RAQCC will not have any regulatory authority or responsibilities.

4. Monitoring of Ambient Air Quality Exceedances

As noted in the letter of June 26th, the Fort McKay Indian Band has reason to doubt the quality, accuracy and reliability of the current air quality monitoring initiatives in the oils sands region. While it is clear that Syncrude currently operates their air monitoring network consistent with the requirements of Alberta Environment, the Fort McKay Indian Band would suggest that a comprehensive review of the adequacy and nature of these and other industry-government facilities be undertaken.

Consistent with earlier deliberations, we therefore suggest the establishment of a regional air quality monitoring committee, composed of representatives of the Band, Syncrude, Suncor, ERCB, the City of Fort McMurray, and Alberta Environment in order to review the type and location of monitoring stations for air quality parameters in the region. It is noted that Syncrude has previously agreed with this suggestion. In the Band's view, there is a specific need for enhanced monitoring capability in and around the community of Fort McKay.

5. Quality of SO_2 Emissions and the Impact on Water and Soil

As noted in the June 26th letter, it is essential to have baseline information to determine whether the existing levels of wet and dry

the lakes and soil in the area. The EIA from Syncrude has indicated that "the effects of sulphate deposition on terrestrial and aquatic ecosystems in the region are subtle and remain poorly understood". The Fort McKay Indian Band is pleased that Syncrude continues to support the concept of a joint regional air quality research committee and it is suggested that this committee be tasked with the work of attempting to verify or establish an annual target for sulphate deposition in the region.

6. Hydrocarbon Emissions

Both syncrude and the Fort McKay Indian Band have come to the conclusion, through the Regional Air Quality Task Force, that insufficient data presently exists concerning hydrocarbon emissions in the region. As such, both parties agree that it is presently not possible to undertake a proper evaluation of this concern. The Fort McKay Indian Band continues to note that at present there is no monitoring system in place which is capable of analyzing the character, quality and quantity of hydrocarbon emissions at the plant site or in Fort McKay although Syncrude has recently taken some initiatives in this direction.

The existing monitoring site at Fort McKay measures levels of hydrocarbons, however, it does not distinquish as to the character and quality of these emissions. The initial data on hydrocaron monitoring at the Fort McKay site indicates the fumigations are indeed occurring at levels which may be harmful, or which represent a significant nuisance, to community members. It is also suspected that this problem also exists for the community of Fort McMurray. This appears to be particularly true during times of significant valley inversions, or cross-wind shears which may cause hydrocarbon concentrations to exceed the monitoring capacity of the available equipment in the region. Information on the toxicity and effects of hydrocarbon emissions suggests that these atmospheric pollutants may cause significant impacts on human, animal and plant communities.

The Fort McKay Indian Band and Syncrude jointly believe that the issue of hydrocarbon emissions should be pursued via the Regional Air Quality Co-ordinating Committee and that the objectives for the task force should be as follows:

a) to establish a monitoring protocol for these emissions as soon as possible.

b) to immediatley establish a monitoring network for these emissions in the region;

c) to investigate and establish operating procedures which minimize or eliminate noxious emissions to the atmosphere.

The Band believes that, in addition to the above, a review of possible new enforcement standards and regulations for these compounds should be established as soon as possible. This is consistent with regulations and approaches which have been established in some parts of the United States. The overall intent of this initiative would be to establish the sources of hydrocarbon emissions in the region and to reduce these compounds from the airshed of the region.

The Band and Syncrude agree that studies are required to examine the rates and routes of dispersion of hydrocarbon emissions, including evaporation and indirect emissions, for the region. This initiative should be accompanied by a model which indicates the movement and deposition of hydrocarbons in the vicinity of Fort McKay, in a wide variety of atmospheric conditions which are known to occur for the site.

The Band has estimated that there are approximately 90 million gallons of naphtha which are disposed of into the Suncor and Syncrude tailings ponds annually. It is suggested that this may be one major source of hydrocarbon emissions. The Band recognizes that Syncrude has made a major advance in minimizing naphtha losses to the tailings pond. The "naphtha recovery unit" developed by Syncrude is acknowledged to represent the state-of-the-art in naphtha recovery from centrifuge plant tailings. One task of the air quality task force should be to examine how this or other technological options could be implemented throughout the region. Further careful studies as to the operational methodologies for disposal of hydrocarbons during normal and upset conditions should be carefully examined by the ERCB, Alberta Environment, and the Regional Air Quality Co-ordinating Committee.

7. Heavy Metal Emissions

The Fort McKay Indian Band recognizes that Syncrude should not be in a position to discuss emissions from any facility other than their own and further recognizes that Syncrude has made exceptional efforts to document levels of metals emissions from their plant. However, the

Regional Air Quality Task Force, while noting that sufficient data exists to establish the probable regional emission rates of metallic elements, nonetheless, recommended that Alberta Environment consider having a metals emission survey conducted of the Suncor stacks in order to complete and verify the metal emissions inventory for the region. The Air Quality Task Force has also noted that ambient levels of most metals in the region are well below Ontario standards established for urban areas.

The Band does not accept that elevated ambient levels of metals should be accepted in this region, regardless of standards or emission rates elsewhere in North America. It is the position of Fort McKay that the ambient air quality of the region would be protected. The Band has enjoyed exceptionally high quality air quality for generations and does not accept significant deteriorations in the ambient air quality.

The Band will not accept air quality standards similar to those for large urban centers. The Band was originally located in an isolated region, and has always had, and expects to continue to have, exceptionally high quality air. It is clear that the lichen monitoring network established by Syncrude in the 1970's has indicated an accumulation of heavy metals in this region. While the Band accepts that this is the only valid study in the area, and commends Syncrude for its commitment to continue such work, Fort McKay recommends that air quality research regarding heavy metals impacts be maintained through the air quality task force. Further, the Band suggests that it be involved in the planning, direction, implementation, and review of such initiatives. Syncrude and the Fort McKay Indian Band both agree that the suggested research program should be considered by the Air Quality Task Force upon its assumption of its recommended research co-ordination role.

The Band notes that at present there are no regulatory standards for heavy metal emissions other than levels established for particulate emissions per kilogram of emission. The Band believes that this standard may not be appropriate in light of the total regional volume of emissions of heavy metals. The current standards fail to consider the total volume of such emissions over the long term. It is therefore jointly concluded and recommended by Syncrude and the Band that a research program be continued and expanded to monitor and measure the effects of heavy metal and particulate emissions on the vegetation and animal life in the area.

In addition the Band considers that such studies should be extended to include human health. The Band further recommends that the ERCB and Alberta Environment direct producers to undertake further research to examine whether other economically feasible engineering technologies are available to substantially lower emission rates of particulate and heavy metals.

8. Flared Emissions From the Syncrude Plant

All parties recognize that Syncrude has greatly improved the emissions record as a result of flaring activities. It is recognized that SO2 emissions form flaring has been reduced from 28.2 t/d in 1983 to 2.0 t/d in 1986.

Nonetheless, it is suggested tha the ERCB and Syncrude, in conjection with Alberta Environment, review flared emissions at Syncrude, especially those which may cause contravention to ambient air standards. It is recommended that these dicussions on future possible research be carried out through the formation of the aforementioned Regional Air Quality Co-oridnating Committee.

9. Studies on Impacts of Emissions

It is jointly recommended that the Regional Air Quality Co-ordinating Committee look into the effects of sulphate deposition on vegetation, animals and ecosystems processes in the region as these effects as stated in the Syncrude monograph 85-5 are "subtle and remain poorly understood". The Band and Syncrude believe that it is important to initiate research on the accumulation and incorporation of atmospheric emissions into the food chain in the area, especially as they may influence or affect animals in the region. The Band is also of the opinion that further research on the potential effects of heavy metals and hydrocarbon emissions on people in the region is needed, especially intake and accumulation of metallic elements through the food chain or by inhalation.

The Band and Syncrude are also of the opinion that a joint research program is desireable but should not be a requirement of any operating approval, to further investigate the impact of atmospheric emissions on the ecosystem in the region, especially the accumulation of metallic elements in the vegetation and food chain.

10. Reclamation and Regional Resource Land Use, Resource Competition

Syncrude and the Fort McKay Indian Band agree that alternative reclamation and regional land use strategies are possible.

The SERG Participants agree that the Ft. McKay Band will table their concerns on possible integrative options in Reclamation Planning to the appr priate D and R Committee to examine options for forestry and wildlife habitat development and integration.

11. Water Resources Tailings Ponds

In the final recommendations to the ERCB/SARG process dated May, 1986, it was concluded that:

> "the Band questions the philosophy and continued practice of a total containment strategy, as this would appear to potentially worsen hydrogeological concerns for the tailings pond over time. Instead, parallel treatment and disposal strategies should be reviewed to hasten, or reduce the volume of contained tailings water in conjunction with a wider review of tailings management practices at the site".

Syncrude and the Fort McKay Indian Band therefore jointly agree that in the long term it is desirable to minimize the accumulation of tailings water. The Fort McKay Indian Band believes, however, that any discharge of contaminated tailings pond water at this time is unacceptable.

It is jointly agreed that Syncrude will involve the Band should significant alternatives be contemplated regarding site water management. Any such review of site-water management, if required, should be led by appropriate Alberta Government agencies, and Fort McKay to ensure that sound long-term environmental management practices in regard to the routing of runoff streams to and from the tailings pond, and well understood and carefully examined.

12. Groundwater Concerns

The parties are satisfied that there does not appear to be a significant danger of contamination of groundwater aquifers from the tailings pond or groundwater seepage resulting from the project although continued monitoring programs will be done.

APPENDIX C

The Fort McKay Indian Band: Community Socio-Economic Concerns in Relation to the Syncrude Expansion Project

Submitted to

Syncrude Expansion Review Group

by

Nichols Applied Management
Economic and Management Consultants

on behalf of

The Fort McKay Indian Band
and
Syncrude Canada Ltd.

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1. INTRODUCTION

1.1 BACKGROUND

In April 1987, environmental and socio-economic impact assessment reports relating to Syncrude Canada's proposed expansion project were completed and subsequently distributed to government regulatory agencies and other interested groups.

Following its review of the socio-economic impact assessment (SEIA), the Fort McKay Indian Band submitted a letter to Syncrude Canada Ltd. outlining its concerns regarding the report. Among the Band's concerns were the following:

1) the SEIA does not adequately recognize and address the various developmental barriers which Fort McKay experiences and which impede the community's ability to participate in new resource projects such as the one proposed; and,
2) the SEIA does not define the specific policies, programs, and initiatives to be undertaken by Syncrude having regard to Native socio-economic development generally, and to the community of Fort McKay, more particularly.

The Fort McKay Indian Band reviewed these issues at a SERG meeting held in Edmonton on July 14, 1987. It was agreed at that time that representatives of Syncrude and the Band would work together during the following weeks to document and assess the expressed concerns as a first step in formulating plans to resolve those matters of joint interest and responsibility.

Following the SERG meeting, representatives of the community met independently to discuss the perceived deficiencies of the SEIA, the anticipated impacts arising from the proposed project, and the local developmental barriers which will constrain the ability of the community to participate in new economic opportunities which might occur in the region. This information was conveyed to Syncrude representatives in a meeting held on August 18.

The report which follows attempts to summarize the views expressed by the Band at that meeting. In its draft form, the report has been reviewed by the Band and suggested modifications have been incorporated in this document.

1.2 OBJECTIVES OF THE REPORT

The main objective of the report is to describe the views of Fort McKay with regard to: 1) the SEIA and the anticipated impacts of the expansion project, and 2) the key

anticipated impacts of the expansion project, and 2) the key socio-economic developmental barriers faced by the community. In the coming weeks, these issues will be examined by the two parties with a view to exploring ways to resolve them.

1.3 ORGANIZATION

Section 2 of the report documents the socio-economic issues raised by Fort McKay in its correspondence and meetings with Syncrude. Section 3 summarizes those areas which the Band feels deserve specific scrutiny by Syncrude.

2. COMMUNITY SOCIO-ECONOMIC CONCERNS AND DEVELOPMENTAL BARRIERS

2.1 PREFACE

This section of the report documents the key socio-economic concerns and developmental barriers in Fort McKay, as perceived and articulated by representatives of the community.

2.2 FUNDING FOR LOCAL GOVERNMENT AND ADMINISTRATION

A majority of the residents of Fort McKay are members of the Fort McKay Indian Band, which is governed by an elected Chief and Council. The Band provides a variety of local government functions to its members and relies heavily on financial support from the Department of Indian and Northern Affairs (INAC) to deliver those services.

The Band views as very unsatisfactory the present financial arrangements under which it operates. Through the funding formula used by INAC, small bands such as Fort McKay are allotted budgets which are considered inadequate to maintain a minimum administrative and government structure and, in real terms, these budgets have declined in real terms due to federal spending restraints. The inadequacy of current funding arrangements is exacerbated by the extraordinary demands placed on the community by the resource-based growth and development which is occurring in the region. The Band itself has few alternative financial resources with which to supplement the INAC funds, which it believes are deficient by approximately $100,000 per year. Over the past two years, Syncrude has contributed $50,000 annually for the hiring of a Band Administrator and this has partially mitigated the financial pressures on the Band.

Without sufficient financial resources, the Band cannot maintain the management and administrative capacity to carry out required planning and development activities, and it faces an on-going problem in terms of recruiting and retaining competent staff. Wage and salary levels in the region are high and qualified staff tend to relocate to higher-paying positions with other employers. The demands placed on the Band's administrative manpower are excessive and compound the relatively poor local working conditions. A considerable amount of staff time is also taken by the need to identify and access various sources of external financial assistance.

In sum, the Fort McKay Indian Band sees as an urgent priority the development of an adequate and stable funding base it if is to meet the needs of its members. Over the longer-term, the Band is hopeful that its various business

enterprises will grow and prosper to the point that these will reduce the reliance on short-term and ad hoc external funding sources.

Fort McKay is a hamlet administered as part of Improvement District 18 by the Alberta Department of Municipal Affairs; a member of the community is represented on the I.D. Advisory Council. With municipal responsibilities for the community, the I.D. also has a funding role and present arrangements in this regard are considered by the Band to be unsatisfactory as well. I.D. 18 secures a major share of its revenues through property taxation, and the Syncrude-Suncor facilities and related operations constitute a large part of that revenue base. At the same time, the Improvement District is a large one, extending from the N.W.T. border in the north to the Lac La Biche-Cold Lake areas in the south. Fort McKay has expressed concerns that while the nearby oil sands operations generate significant tax revenues to the I.D., much of that is spent in southern parts of the jurisdiction far removed from the oil sands area, while the community itself, located in close proximity to the resource activity, receives little direct benefit. Local services, facilities and infrastructure in the Fort McKay are viewed as very deficient.

The Fort McKay Band has stated that the local administrative demands on the community have been compounded or precipitated in some part by the development and operation of the Syncrude plant and that the company has some financial responsibilities in this area.

2.3 INFRASTRUCTURE AND FACILITIES

The standard of community facilities available to Fort McKay residents is considered to be very low and to have an adverse effect on the social and cultural health and structure of the hamlet. The offices of the Fort McKay Indian Band -- the main focus of local government in the community -- are located in trailers which are not adequately sized or configured to meet the Band's administrative and program needs. There is no community hall or meeting place to serve various local functions. The Band-owned convenience grocery store -- the only retail outlet in Fort McKay -- is accommodated in a small, older structure and there are no laundromat facilities, despite the fact that piped water and sewer is not yet available to individual residences.

It is hoped that these specific deficiencies will be corrected through the planned construction during the coming year of a community multiplex although some elements of the financing plan remain in doubt.

Fort McKay does not yet have piped water and sewer services although the plans for these have been approved and installation is expected during 1988.

Many houses in Fort McKay are being upgraded to accommodate the water and sewer system and the Band is able, through INAC, to finance a modest housing construction program each year. The major concern of the Band with regard to housing relates to the limited number of undeveloped lots available in the community. In the Band's view, a new subdivision will be required to accommodate natural growth in the community over the next few years, and also to provide for the possible in-migration of former residents now living away from Fort McKay. Any growth of the community occasioned by the Syncrude expansion project will further expand the demand for new housing. This implies the need to carry out physical planning activities and ensure that the related urban infrastructure is financed and in place as required.

The Band has identified the need within the community for a senior citizens' home and expects to address this requirement in the near future.

Another area of local concern relates to the lack of a paved road from a point north of the Syncrude turn-off to Fort McKay. Improvements to that road would enhance the accessibility of community residents to services and employment opportunities within the region.

2.4 PROGRAMS AND SERVICES

The Band has identified a number of service delivery gaps or shortfalls which reduce the ability of community residents to participate fully in new economic opportunities that arise in the area.

The Band operates employment training, addictions counselling, and social services programs with financial support from INAC, the Federal Department of National Health and Welfare, and Alberta Social Services and Community Health, but the funding and resource assistance available from these agencies is considered to be inadequate. The limited funding available for these services, together with the workload on other members of the Band administration, has meant that the programs are inadequately coordinated and managed. Underlying community social problems -- attributed in some part to the impact of rapid changes in the traditional economic structure of the local area and the difficulties of adapting and adjusting to those changes -- serve as barriers to the participation of the community in the new business and employment opportunities available to it.

The community proposes to establish an Employment and Training Centre and has applied for support funding from government. An important focus of the Centre will be to work with youth in the community, stressing the importance of further education and training, and motivating them to obtain the skills necessary to take full advantage of available employment and career alternatives.

Also recognized as a deficiency in Fort McKay is the absence of a daycare program and facility. This serves as a barrier for some adults in seeking employment outside the home or taking additional training or academic programs.

2.5 BUSINESS DEVELOPMENT AND CONTRACTING

Fort McKay has as a high priority the development of community-owned businesses which not only will generate jobs for local residents but, through the profits earned, will supplement the inadequate funding available to the community from external sources.

A number of concerns have been expressed by the Fort McKay Band regarding its contracting experiences with Syncrude. The Band, through a wholly-owned business, currently has bussing and janitorial contracts with Syncrude. These contracts employ five residents. In the Band's view, the total value of contracts held by community-based businesses is low, the contracted services provided are relatively low-skilled, and the contracts themselves -- which have been awarded on a negotiated basis -- offer little opportunity for profit.

The community believes that its contracting capabilities have improved dramatically over the past two years and that it is in a position to successfully carry out much larger and more diverse contracts, but that local firms have been offered limited opportunity to bid on such contracts.

The Band has the perception that Syncrude places almost all of its requirements for goods and services to tender and that the only way the community realistically can secure a sizeable contract with the firm is on some form of negotiated basis. The Band feels that negotiated contracts can yield competitive terms and performance for Syncrude while at the same time providing developmental and employment benefits to Fort McKay. It has been suggested as well that the linkage between the procurement and native development sections of the firm is not as strong as it might be and that the contracting experience of Fort McKay has suffered as a result.

As initial steps in addressing Fort McKay's concerns in the contracting area, the Band has requested that Syncrude:

1. articulate, as part of its Native Development Program, the firm's specific policies and guidelines relating to Native contracting;
2. identify contracts leading up to and during construction of the expansion project that it will make available on a sole-source negotiated basis and specify any qualifying conditions governing eligibility as a sole-source supplier;
3. specify the organizational structure and resources within the firm to be devoted to Native procurement concerns.

2.6 EMPLOYMENT

It is estimated by the Band that twenty five residents of Fort McKay are employed by Syncrude on a full- or part-time basis. The number of unemployed adults in the community ranges between approximately thirty and sixty, depending on the time of year, and with young people entering the labour force on an on-going basis, employment concerns have considerable local importance.

In the Band's view, the proposed agreement between the Athabasca Native Development Corporation (A.N.D.C.), Syncrude Canada Ltd, and the federal and provincial governments will establish broad objectives for native training and employment but that the specific elements of a program to achieve those objectives should be documented.

The Band has requested that Syncrude specify the policies and plans it will adopt to support the hiring, training, and advancement of Natives, and the internal staffing and resources that will be assigned to these tasks. The Band would like the firm to develop and articulate a Native equity employment plan which would state the proactive measures to be taken to achieve the firm's Native employment objectives.

The Band is also interested in understanding what initiatives Syncrude has taken in the context of current capital programs, and proposes to undertake in respect of the expansion project, to encourage its contractors to employ Native people.

2.7 PROJECT IMPACTS

Many of the foregoing issues are of a general concern to the Fort McKay Indian Band and are not specifically addressed to the expansion project itself, although some may be exacerbated or reinforced if the

project proceeds. However, a very specific concern of the Band involves security in the community during project construction. The rural R.C.M.P. detachment, which is responsible for policing a very large geographic area, cannot provide 24-hour security for the community, which the Band believes is necessary to discourage intrusions from the large work camp that will be operated nearby. The Band is concerned that the necessary policing arrangements be in place during the project construction phase.

3. IMPLICATIONS TO SYNCRUDE CANADA LTD.

As part of its review of community socio-economic concerns and developmental barriers, the Fort McKay Indian Band has suggested that a number of specific areas be addressed by Syncrude. These are reiterated in summary form below.

Area of Concern	Activities Requested of Syncrude
Funding for local government	• state company's policy relating to the future provision of community-based financial assistance to Fort McKay.
Community infrastructure and facilities, programs, and services.	• state company's policy relating to the future provision of community-based financial assistance to Fort McKay. • assist community as required to access identified local improvements from senior levels of government.
Business development and contracting	• articulate specific policies and guidelines relating to Native contracting. • identify contracts which firm will make available on a sole-source negotiated basis. • specify organizational structure and resources which the firm will devote to Native procurement. • award sizeable negotiated contract to a community-owned business.
Employment	• specify policies and plans related to the hiring, training, and advancement of Natives within the organization. • document the internal staffing and resources that will be dedicated to the realization of those plans.

- develop a Native equity employment plan with proactive measures to achieve firm's Native employment objectives.
- state initiatives to be taken to encourage contractors to employ Natives.

Project impacts

- ensure availability of 24-hour policing security to community during project construction phase

APPENDIX D

SERG PARTICIPANTS

Al Hyndman	-	Syncrude Canada Ltd.
Don Thompson	-	Syncrude Canada Ltd.
Jerome Slavik	-	Fort McKay Indian Band
Ron Wallace	-	Fort McKay Indian Band
Chief Jim Boucher	-	Fort McKay Indian Band
Jerry Lack	-	Alberta Environment
Larry Brocke	-	Alberta Environment
Jeff Bondy	-	Forestry, Lands and Wildlife
Ralph Evans	-	Energy Resources Conservation Board
Richard Houlihan	-	Energy Resources Conservation Board
Brahm Prasad	-	Energy Resources Conservation Board

APPENDIX E

SYNCRUDE EXPANSION EMISSIONS TECHNOLOGY STUDY

Prepared for the

SUNCRUDE EXPANSION REVIEW GROUP

Financed by

ENERGY RESOURCES CONSERVATION BOARD

and

ALBERTA ENVIRONMENT

Administered by

ENERGY RESOURCES CONSERVATION BOARD

D Ronald Hickey, P Eng
October, 1987

EXECUTIVE SUMMARY

In early 1987 the Syncrude Expansion Review Group formulated the concept of the Syncrude Expansion Emission Technology Study. The Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment agreed to finance the undertaking and its implementation was administered by the ERCB.

The project was conceived as an independent engineering study with the following objectives:

1) Verify the claims in Syncrude Canada Limited's application to the ERCB as to the levels of emission of sulphur, vanadium, nickel, lead and particulates to the atmosphere.

2) To compare the technologies proposed with at least one other which would have the possibility of being the best practical technology (in terms of emissions and synthetic crude oil yield) for the expanded facility.

3) To provide a measure of what the cost might be to obtain the lowest possible sulphur and heavy metals emissions using best available technology.

The study was undertaken by an independent consultant, who reviewed Syncrude Canada Ltd's (SCL) "Application to the ERCB for Expansion of the Syncrude Canada Ltd Mildred Lake Plant", dated April 27, 1987, and several associated documents, including internal SCL material.

Using a computer model of the upgrading segment of an oil sands plant which had been developed for Alberta Oil Sands Technology and Research Authority, the hydrocarbon, sulphur and heavy metals balances of the Application were paralleled and indeed closely confirmed. That is to say the yield of synthetic crude oil SCL predicts is correct, and its estimate of reduced sulphur dioxide emissions. While they forecast a mild reduction in particulate emissions, it is felt to be safer, for the purposes of this study, to assume that there will be no change; however it is easily shown that the contained heavy metals are significantly lower and consequently their emission rate will be reduced.

The computer model was also used to replace the expansion process unit configuration with a high conversion hydroprocessing alternative. This was postulated as "best practicable technology". The result was disappointing in that it did not produce an improvement in synthetic crude oil yield while causing an increase in sulphur dioxide emission.

Employing a study prepared for Alberta Environment by Dynawest Projects as a basis, capital and operating costs for the addition of Flue Gas Desulphurization on the main stack of the plant were estimated. This step would reduce sulphur dioxide emission rates from 250 tonnes daily to 25 tonnes per day, as well as greatly reducing particulate and heavy metals emissions. The all-in cost would be about 1300 dollars per tonne of sulphur captured.

From the same source the economics and effect on sulphur emissions of selection of an alternate, more efficient, Claus sulphur plant tail gas clean-up process than the one chosen by SCL, were examined. The impact of this approach was not nearly as dramatic and effective as the application of Flue Gas Desulphurization to the main stack.

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1.0 INTRODUCTION

The Syncrude Expansion Review Group (SERG) consists of members from:

The Fort McKay Community
Forestry, Lands and Wildlife
Alberta Environment
The Energy Resources Conservation Board
Syncrude Canada Ltd

It was formed in September 1986 to facilitate discussion of the proposed Syncrude Canada Ltd (SCL) major expansion by these interested parties. The dialogue is to take place as the project plans are being developed, and is calculated to provide broad understanding of all factors involved to everyone.

Amongst other business conducted by SERG was the formulation of the concept of an independent engineering study to:

1) Verify the claims in SCL's application to the Energy Resources Conservation Board (ERCB) as to the levels of emission of sulphur, vanadium, nickel, lead and particulates to the atmosphere.

2) To compare the technologies proposed with at least one other which would have the possibility of being the best practical technology (in terms of emissions and synthetic crude oil yield) for the expanded facility.

3) To provide a measure of what the cost might be to obtain the lowest possible sulphur and heavy metals emissions using best available technology.

This **SYNCRUDE EXPANSION EMISSIONS TECHNOLOGY STUDY** is the result of these deliberations, it is administered by the ERCB and financed by the ERCB and Alberta Environment (AENV). It has as its objectives the three items enumerated above.

1.1 STUDY METHODOLOGY

The study was undertaken by a single, independent consultant, (hereinafter referred to as Consultant) who reviewed SCL's "Application to the ERCB for Expansion of the Syncrude Canada Ltd Mildred Lake Plant", dated April 27, 1987, and several associated documents. Also the licensor of the Fluid Coking process was consulted.

Utilizing a computer model of the upgrading segment of an oil sands plant developed by Consultant for Alberta Oil Sands Technology and Research Authority (AOSTRA), the hydrocarbon, sulphur and heavy metals balances of the Application were paralleled to see if they could be verified. Hydrocarbon yield and the disposition of sulphur and metals were scrutinized.

Syncrude Canada Ltd provided supplemental information as required to procede with the verification. One important document was the Environmental Research Monograph 1984-2, "A Study of the Metallic Emissions for the Main Stack at Syncrude's Mildred Lake Plant", a measurement and analysis of the subject emissions by Concord Scientific Corporation. This is the most comprehensive and carefully performed work on the subject, and it was used to develop distribution curves for the rate of solid atmospheric emissions as they were in 1984 and as they will be after the proposed expansion.

In addition internal SCL documents were examined to ascertain the premises leading to the formation of their sulphur

dioxide (SO_2) frequency of emission graph, found in the application.

The AOSTRA oil sands computer model, mentioned above, was also used to replace the expansion process unit configuration with a high conversion hydroprocessing alternative. This was postulated as "best practicable technology" and the resultant liquid hydrocarbon yield was examined, as were the effects on emissions of sulphur, particulates and heavy metals.

Finally, utilizing a study prepared for AENV by Dynawest Projects as a basis, capital and operating costs for the addition of Flue Gas Desulphurization on the main stack of the plant were established. This step would reduce SO_2 emission rates from about 250 tonnes daily to 25 tonnes per day, as well as greatly reducing particulates and heavy metals emissions, in most cases.

From the same source, the economics and effect on sulphur emissions were examined of selection of an alternate, more efficient, Claus sulphur plant tail gas clean-up process than the one chosen by SCL.

1.2 ACKNOWLEDGMENTS

The writer would like to acknowledge the contributions made to this evaluation by a number people.

Firstly, of the ERCB staff most notably helpful were Mr R. G. Evans, Manager of the Oil Sands Department, Dr. Richard N. Houlihan, Director of this Project and Kenneth Bahadur.

The representatives of the Fort MacKay Community, Dr. R. R. Wallace, Mr Jerome Slavik and the Chief James Boucher, provided continuous wise counsel, most particularly at the outset of the study.

The advice of Alberta Environment was appreciated, particularly as contributed by Jafir Jaferi.

Finally, this work could not have been undertaken without the complete cooperation of Syncrude Canada Ltd, who unstintingly provided all information that was requested.

2.0 PROCESSING of HEAVY BITUMEN

Oil sands bitumen, as it is separated from the sand by the Clark Hot Water process in a surface mining installation, or comes from the ground in an in-situ project, is a heavy, black, viscous material that has little practical use, except as paving grade asphalt.

The very least that must be done, is to reduce its viscosity to the point where it can be pumped through existing crude oil pipeline networks. This is sometimes accomplished by diluting the material with condensate, a light hydrocarbon liquid which is the by-product of natural gas processing. The problem with this approach, is that the supply of condensate is forecast to diminish, while the production of oil sands bitumen and heavy crude oil is predicted to increase. Also it does nothing to increase the value of the bitumen.

The reason for the unfavorable properties of bitumen is that there is too much "heavy" material in it, that is to say that the portion which boils above 525°C is excessive. In Alberta light crude oil, this fraction amounts to about seven volume per cent, while in oil sands bitumen, it exceeds fifty per cent.

All crude oil is mostly hydrocarbon, chemical compounds composed of hydrogen and carbon. The portion boiling above 525°C has a higher proportion of carbon, that is to say has a higher carbon to hydrogen ratio. Over a period of sixty years, many have sought to develop processes to improve, or upgrade, the pitch, or 525°C plus fraction of crude oils. Success has been obtained, but the expense is usually quite high.

The general approach to upgrading this material is to reduce the carbon to hydrogen ratio. This can be done in two ways.

The first is carbon rejection, where a portion of mass is produced that has a very great deal of carbon in it and little hydrogen. This residue, if solid, is usually called coke, and if liquid, may be called pitch. The remainder then has a better carbon to hydrogen ratio, is a liquid, and is a more useful product to refiners. This effect is usually realized by subjecting the stream to high temperature in such a manner that the solid coke which will be formed does not impair the operation in any way.

The second method of upgrading is called hydrogen addition. It is usually accomplished in a reactor, at high temperature and pressure, in the presence of hydrogen. There is also a high carbon content residue from this procedure, but there is significantly less of it and there is more of the desirable liquid than in the carbon rejection approach.

2.1 CARBON REJECTION

Examples of commercially applied carbon rejection processes are delayed coking, Fluid Coking, Flexicoking and Eureka. The first two are employed respectively, at the only two surface mining oil sands plants. Fluid Coking and Flexicoking have been selected in some applications to the ERCB for oils sands plants which were approved but subsequently deferred.

Fluid Coking is employed at Syncrude Canada Ltd's Mildred Lake plant and will be briefly described so that a better understanding may be had of SCL's application to the ERCB for its expansion project.

The key element in this process, developed and licensed by Exxon Research and Engineering, is that the coking reaction takes place in a fluidized bed of coke particles. The hot feed which may be any fraction from whole bitumen to the 525^{o}C plus vacuum bottoms, along with some recycled liquid is pumped into the reactor, as a spray, right into the very hot

fluidized bed. The temperature of the particles provides the necessary heat for the cracking, or coking reaction. The lighter liquid product, as it is formed, vapourizes and leaves the reactor. The hot vapour goes into the scrubber, where it is quickly reduced in temperature to a point where cracking no longer takes place. It then goes to a conventional fractionator.

In the reactor, the coke formed, which amounts to about twenty weight per cent of the feed, is laid down as a fresh layer on the coke particles in the fluidized bed. The coke, now lower in temperature, flows out the bottom of the reactor and up a riser into the second major vessel of the Fluid Coking unit, the burner.

In the burner, a precisely controlled amount of air is introduced and a portion of the fluidized bed of coke is burned. Thus the coke is reheated and the necessary heat for reaction is supplied. The hot coke flows into an overflow well, down, then up the hot coke riser back into the reactor. At the same time the net, or product, coke is withdrawn from the burner and sent to storage. Because the coke is only partially combusted, there is a lot of carbon monoxide (CO) in the flue gas leaving the burner. This stream goes to the CO boiler where the CO content is burned to produce steam.

Also contained in the flue gas stream leaving the burner and flowing to the CO boiler is sulphur, the amount bears about the same proportion to the mass of burned coke as there is sulphur in the product coke. From another source, the Claus unit, where H_2S recovered from various plant fuel gas streams is converted to elemental sulphur, the tail gas (really a flue gas in composition) containing some sulphur, is also fed to the CO boiler for the sulphur content to be incinerated. In the CO boiler all the sulphur is burned to SO_2.

In order to maintain proper fluidization of the coke, its particle size range must be controlled. This is done by applying high speed steam jets which agitate the fluidized bed and cause significant attrition of coke particles. Some coke fines result from this operation. In the burner, there are two-stage cyclones which retain the coarser particles entrained in the flue gas flowing to the CO boiler, but allow the finer ones to pass on through.

In the bitumen, as mined and extracted, contained in the heaviest fraction are significant amounts of the heavy metals vanadium and nickel. They total about 0.3 kilograms per cubic metre of bitumen, or around 14,000 kilograms per day. For bitumen feed, essentially all the metals end up in the product coke, and the coke fines which enter the CO boiler. About four to six per cent of the metals are in the fines.

Similarly, there is about one per cent, by weight, of clay in the bitumen after extraction from the sand. This amounts to about 430,000 kilograms of clay per day in the expansion program. Again this solid material ends up entirely in the product coke and the coke fines, and in the same proportions as the heavy metals.

Thus the product coke, and the coke fines have about the same composition, and it is roughly:

TABLE 2-1

Element	Content Weight per cent
Carbon	79.1
Hydrogen	3.9
Sulphur	7.0
Clay + other	9.8
Vanadium + Nickel	0.2

There is also about 0.01 weight per cent of lead in the mixture, a relatively small amount compared to the nickel and vanadium.

The flow rate of fines into the CO boiler varies significantly but the average has been established at about 155 tonnes per day, which compares with the 3500, or so, tonnes per day of product coke. At the exit of the CO boiler are the electro static precipitators, these devices capture over 98 per cent of the fines, preventing them from escaping to the atmosphere. Thus the average emission of particulates to the atmosphere is 3 tonnes daily. The average content of the heavy metals is tabulated below in Table 2-2.

TABLE 2-2

Total particulates,	kg/day	3,054
Vanadium,	kg/day	2.8
Nickel,	kg/day	0.8
Lead,	kg/day	0.32

The foregoing figures are from a careful survey of SCL's main stack, that is to say measurement of rates and analysis of content, done by an outside contractor in 1984.

2.2 HYDROGEN ADDITION

Hydrogen can be added, but it is also desirable to crack the heavy bitumen to lower molecular weight species as well. There are four such processes offered to industry at this time, two are catalytic and two are thermal. They are at different stages of development. The catalytic ones are well proven commercially at lower conversion, say up to sixty-five per cent of the fraction boiling above 525^{o}C converted to

lower boiling material. The two thermal processes are offered only at high conversion, one is based on fifty year old coal liquefaction technology, and is ready for commercial application, while the second is not quite so far advanced. All of the hydrogen addition processes operate at high pressure and temperature in an atmosphere of hydrogen.

The catalytic processes are H-Oil and LC-Fining (LCF). They are really the same process, in that the two companies who developed it split up after twenty years, but they both continue to offer it to industry. Syncrude Canada Ltd has selected LCF for both its current CAP program, as well as the major expansion which is the subject of its application to the ERCB.

This process is of the type called ebullated bed. The catalyst sits in a "free" state in the reactor, and when the unit is commissioned, the upward flow of heavy oil and hydrogen expands the catalyst bed, and the catalyst particles are suspended in the oil. This permits the operator to withdraw spent catalyst while on the run and to add fresh catalyst to maintain a satisfactory level of average catalyst activity at all times.

The reacted oil flows out through the top of the reactor. While its velocity is enough to suspend the catalyst, it is not so great that the particles are carried over the top. The reactor operates at high temperature and pressure, and there is a major flow of hydrogen gas through it at all times to supply that element for the hydrogenation. The cracking of the bitumen is largely temperature related, while the desulphurization and demetallization are mostly catalytic in origin.

2.3 SUMMARY

Oil sands bitumen, as it is extracted, is not transportable in normal pipelines, nor can it be processed to make regular transportation fuels in existing refineries. To confer these properties on the material it must be upgraded.

The specific requirement is to minimize or eliminate the fraction boiling above 525^{o}C, and/or generally rectify its high carbon to hydrogen ratio. The two common approaches are carbon rejection and hydrogen addition. Several examples of each have been mentioned and the two which will be employed by SCL have been described. As it happens, employing these two processes in series has a uniquely beneficial effect in that it maximizes liquid yield and at the same time actually reduces emissions of SO_2, particulates and heavy metals.

3.0 SYNCRUDE APPLICATION

Consultant's objective was to examine the yields, sulphur and heavy metals balances and emissions provided by SCL and to evaluate their accuracy.

The principle documents employed in this aspect of the study were Syncrude Canada Ltd's Application to the ERCB for Expansion of it's Mildred Lake Facilities. It is dated April 27, 1987 and given the number 870593 by the ERCB. With the Application is the Environmental Impact Assessment for the Expansion of the Syncrude Canada Ltd Mildred Lake Project.

In addition the 1984 Application and Biophysical Impact Assessment for SCL's CAP program were studied. The CAP program will be more or less completed by mid 1988. A considerable amount of internal SCL documentation was reviewed, and discussion held with SCL management and technical personnel. Lastly, discussions were held with Exxon Research and Engineering, licensors of the Fluid Coker.

The hydrocarbon yields, and sulphur and heavy metals balances in the application were paralleled in a computer model of the upgrading portion of an oil sands surface mining project. The model had been prepared to perform work for the Alberta Oil Sands Technology and Research Authority (AOSTRA). The yields of the major upgrading processes in the model were modified to reflect the actual and forecasted experience of SCL.

In the final analysis, the synthetic crude oil (SCO) yield, and the sulphur balances, including SO_2 emissions, were found to be within less than one per cent of those presented by SCL in their application. Thus Consultant considers SCL's SCO yield and sulphur balances to have been confirmed.

3.1 FLUID COKING

SCL has been operating two Fluid Cokers at their Mildred Lake Plant since 1978. During this period they have learned a great deal about these units, and the Fluid Coking process in general. In the earlier years, these complex units did not enjoy an especially good record of reliability. This parallels the experience of other users, who have generally found a fairly long "learning curve" for this process. A tangible expression of SCL's current feeling that they have mastered the operation of their Fluid Coking units, and know how to maximize their throughput, is that their 1984 application to the ERCB was based on a unit time efficiency, that is to say their forecast of the amount of time that these two major upgrading units would spend on stream, was eighty-one per cent. In their current application, SCL are forecasting a time efficiency of ninety per cent. Consultant agrees with this significant change in perception; feeling, as SCL obviously does, that it is warranted by the facts.

The current Fluid Coker feed is a lightly topped Athabasca bitumen. From time to time SCL has held test runs on their cokers to determine the yields obtained from these units. The closure they obtain on mass balance is within five weight per cent. This is about as good as can be done on this process where measurement of liquid mass flow rate is easy but of solids and gases is not.

They have acquired the fundamental unit correlations from Exxon Research and Engineering (ERE), developer and licensor of the process, and have modified them to reflect their own experience and feedstock. This enables them to forecast yields, especially liquids, with respectable accuracy.

In order to estimate the yields to be expected from the Fluid Cokers when feeding the product from the low-conversion

hydrocracking of athabasca bitumen, instead of the bitumen itself, a pilot plant program has been undertaken. Samples of Athabasca bitumen were processed in an ebullating bed hydrocracker pilot plant by a licensor. Some of the pilot plant product was then sent to ERE who conducted a Fluid Coker pilot test on it to establish the yields from this material. These yields form the basis of SCL's CAP program and their current application. They have been modified to reflect the fact that SCL intends, by means of the method of operation of the product atmospheric distillation column in its hydrocracker, to feed the 425^{o}C plus fraction of the hydrocracker product to their Fluid Cokers.

In addition to the foregoing, Syncrude Canada Ltd have another pilot program currently underway, scheduled to be completed late in 1987. This calls for a range of bitumen fractions to be processed in an LC-Finer (LCF) by the licensor, Lummus. Samples of the appropriate LCF products, suitably fractionated will then be sent to ERE for processing in their Fluid Coker pilot plant. In the three tests the coker pilot will be fed bitumen, LCF 425^{o}C pitch and a fifty-fifty mixture of the two. This program is more comprehensive than the previous one, and the distillation of the streams will more properly prepare the fractions of interest to SCL.

3.2 HYDROCRACKING

The black oil hydrocracking process selected by SCL, is of the ebullated bed type. The process was originally developed jointly by Hydrocarbon Research Inc (HRI) and the Cities Service Oil Company. It was called H-Oil, and as was previously noted, has the capability of withdrawing spent catalyst and adding fresh catalyst on the run.

Some years ago the two split, but continued developing and marketing the process. HRI retained the name H-Oil, and have acquired Texaco Inc and Husky Oil Ltd as co-developers.

Cities Service acquired Lummus as a co-developer, and renamed their version of the process LC-Fining. Cities was itself acquired by Occidental Petroleum in a merger, and also AMOCO acquired rights to the process, so the LCF marketers and developers are now Occidental Petroleum, AMOCO and Lummus.

3.3 SYNCRUDE CONFIGURATION

SCL will operate their LCF units in series with the Fluid Cokers, and will achieve a synergistic effect. The LCF unit will crack sixty-five per cent of the 525°C plus hydrocarbon in its feed, but at the same time it will remove sixty per cent of the sulphur and nickel in the feed and seventy per cent of the vanadium. In addition it will convert fifty per cent of the coke forming compounds, or coke precursors, as they are known, to valuable liquids. The above cited values will not vary appreciably, because the daily withdrawal of spent catalyst and its replacement by fresh, maintains the catalyst very close to a constant (equilibrium) level of activity.

The limiting factor in Fluid Coker operation is the amount of coke precursor in the feed. As it happens the heavier LCF product which will constitute the Fluid Coker feed has proportionately more of these compounds in it, so there will be fewer barrels per day of coker feed, but the overall effect is that less coke is formed per barrel of raw bitumen charge, hence more of the valuable liquid.

That is not all of the benefit. The coker feed will also have less sulphur and heavy metals in it, so that emissions of these elements from the coker burner and thence the CO boiler will be reduced. All the clay in the extracted bitumen will end up in the product coke, and the coke fines. As there is more bitumen incoming, there will be more clay in the coke and the coke fines. However, this will not affect the rate of emissions, and it is not foreseen that the higher propor-

tion of clay will have any adverse effect on the environment.

In summary, then, the Fluid Cokers will still be operated at maximum throughput, and in fact the absolute production of coke will be slightly increased, but the average amount of coke per barrel of bitumen processed will be reduced, and the valuable liquid yield will be increased. Because the sulphur level in the coker feed is reduced, so then will the emission of sulphur from the Fluid Coker burner, and thence the CO boiler be reduced. Finally, it is thought that the emission of particulates will remain substantially unchanged, but because of the lower levels of vanadium, nickel and lead in the Fluid Coker feed, proportions of these heavy metals in the particulates, and thus their rate of emission will be reduced.

The estimated yields from the LCF, and subsequently when LCF residue is charged to the Fluid Cokers, have been obtained from a pilot plant program conducted some years ago by SCL, as was discussed in the previous section. As was also noted there is a a more extensive program scheduled to be concluded late in 1987 which will reexamine the subject.

3.4 YIELD COMPARISON

Consultant has run three separate computer simulations to examine the validity of liquid yield, sulphur and heavy metals balances. They parallel the amended Post-CAP and Expansion cases of the current application and the Pre-CAP, or base case of the 1984 application. The program is a model of the upgrading portion of an oil sands project. It was developed for the Alberta Oil Sands Technology and Research Authority (AOSTRA) in 1984. The major upgrading unit yields have been modified slightly to reflect the actual and expected results

The data from the two applications are contained in the sche-

matic diagrams at the end of this section of the report. The figures are renumbered for this study, but their original numbers are in brackets.

Figure 3.1	(S-8)	Pre-CAP Liquid Yields
Figure 3.2	(3.0.2)	Post-CAP Liquid Yields
Figure 3.3	(4.1.3)	Expansion Liquid Yields
Figure 3.4	(S-6)	Pre-CAP Sulphur Balance
Figure 3.5	(4.1.5)	Post-CAP Sulphur Balance
Figure 3.6	(4.1.6)	Expansion Sulphur Balance
Figure 3.7	(4.1.9)	Post-CAP Solids Balance
Figure 3.8	(4.1.10)	Expansion Solids Balance

In Table 3.1 are seen the liquid yield results obtained from the computer simulations in comparison with those presented by Syncrude Canada Ltd in their applications. The applications do not report gross and burned coke, so these are estimated for the SCL cases as well as for this study. Also the applications do not indicate "chemical" hydrogen consumption, but it is estimated by taking eighty-five per cent of the indicated flow rate and relating it to bitumen feed rate.

In the first two columns, Pre-CAP, the study estimates synthetic crude oil (SCO) production to be 2.4 per cent higher than the application. It is suspected that slightly different coker yields were used by SCL in 1984. Some intermediate streams are different by a similar amount.

In the Post-CAP and Expansion cases all calculated stream volumes are within one per cent of the application values. In Consultant's view, this confirms the SCO yields provided by Syncrude Canada Ltd in their application.

Also of interest in Table 3.1 is the last column where the differences between Cap and Expansion are tabulated. Bitumen throughput is increased 76,000 barrels per calendar day

(bpcd), throughput to the LCF is up 146,000 bpcd, LCF residuum to the cokers is quadrupled, while bitumen to the cokers is down fifty-six per cent. Hydrotreater feed is up 76,000 bpcd, the same as raw bitumen feed, and SCO product is up 80,000, or 104.7 volume per cent on the marginal bitumen.

3.5 EMISSIONS

3.5.1 SULPHUR DIOXIDE

Syncrude Canada Ltd have forecast that sulphur dioxide (SO_2) emissions will go down with the implementation of their CAP program. Their original application so stated and as part of their expansion application they have restated their expectations of the CAP program results.

The two events which lead to this useful result are first; installation of a Sulfreen Claus plant tail gas clean-up unit, and second the fact that the desulphurization aspect of LCF operation produces a Fluid Coker feed of lower sulphur content, three weight per cent versus five for native bitumen.

The Sulfreen tail gas clean-up unit will be commissioned in the latter part of 1987 and could reduce SO_2 emissions by more than thirty tonnes per day. As with many process units, there is some learning involved. The current three stage Claus units operate at an overall sulphur recovery efficiency of 97.5 per cent, start-of-run and around 95 per cent at end-of-run. The Sulfreen plant can boost the overall recovery level to 98.8 per cent, regardless of what stage the Claus plants are in. At Sulfreen end-of-run, the recovery does drift off a bit. To achieve these results requires very careful operation, the air rate must be controlled meticulously and the conditions of operation of the Claus plants are to be maintained so as to minimize formation of COS and CS_2, as these compounds are not converted to sulphur in the

Sulfreen.

When the LC-Finer (LCF) comes on stream in 1988 its powerful desulphurization capability will release nearly three hundred additional tonnes of sulphur per day. There will be a reduction in SO_2 emission in the coker burner, but the additional three hundred tonnes per day of load on the Claus units will increase emission by five or six tonnes per day.

Table 3.2 is a presentation of the study and application sulphur balances in the same style as the yield comparison. The effect of the complete CAP program is not seen very well from the numbers in Table 3.2, because SCL has perceived that the sulphur level in raw bitumen is now averaging 4.85 weight per cent and their 1984 application was based on a feed sulphur content of 4.50 per cent. Back calculation indicates that the reduction in the coker burner will be about 24 tonnes per day of SO_2 and the Claus plant increase will be about eleven tonnes per day for a net reduction of thirteen tonnes per day when the LCF comes on stream in 1988.

SCL, in their application, allowed for "catch-up" heavy gas oil feed to their hydrotreaters containing sixty odd tonnes per day of sulphur. The study model did not accommodate this event. Allowing for this difference, most stream values in Table 3.2 are very close, and again it is felt that the final result, SO_2 emissions as presented by SCL in the application, are confirmed.

As in Table 3.1, the last column has the differences between CAP and the Expansion, as seen in this study. For the expansion, (compared with CAP) sulphur in the total coker feed is down by 330 tonnes per day, or 25 per cent. Somewhat more coke is produced, and a little more is burned, but SO_2 emissions from the burner/CO boiler are down 38 tonnes per day. Against this, sulphur production is up 700 tonnes per day and consequently Sulfreen SO_2 emissions are up 29 tonnes per day.

So in the expansion program, at 249.2 tonnes per day, the net improvement over the CAP results is a modest nine tonnes per day in emission of SO_2. Overall emissions, expressed as tonnes per thousand barrels of bitumen feed, are down from 1.23 to 0.94.

It must be pointed out, though, that SCL have taken a conservative view of sulphur emissions from the Fluid Coker burner and in Claus/Sulfreen plant overall recovery efficiency. A better perspective on SO_2 emissions can be see in Figure 3.9 (which was Figure 4.1.7 in the Syncrude application). It is called "Frequency Distribution of SO_2 Emission Rates", and depicts the situation after expansion. Please note that the Sulphur Balance diagram, Figure 3.6, lists the SO_2 emission rate as 249.2 tonnes per day, but in the frequency diagram the most frequent rate will be 200 tonnes per day.

Consultant was given an opportunity to evaluate the premises that went into the creation of the frequency plot. There were a large number of variables involved, from the sulphur in the bitumen feed through to the efficiency of the Sulfreen unit which were varied over specified ranges on a random basis. For example, the average bitumen sulphur level has been established at 4.85 weight per cent, but it varies around that value with a known standard deviation. The plot was made by conducting a 5000 trial Monte Carlo simulation.

It is the writer's opinion that all the assumptions used were reasonable and that the values of means and standard deviations selected were realistic. Thus the diagram fairly represents the likely pattern of post-Expansion SO_2 emission on a day to day basis. Note also that the tabulated value of 249.2 tonnes per day is not an unreasonable one because it is very close to the ninety-five per cent confidence level. That is to say, given the range of values in day to day operation, the emission rate will be at, or below, 249.2 tonnes per day ninety-five per cent of the time.

In the frequency plot, there are instances of SO_2 emission rates above the permissible limit of 292 tonnes per day. The probability of such an occurrence appears to be less than one per cent. It is not known which particular events lead to these circumstances but the most obvious ones would occur when the Sulfreen unit is down. The two new Claus units are of 700 tonnes per day capacity, and are two stage units. If the Sulfreen unit was down, and one of the older Claus units also, but everything else was operating, calculations suggest that the emission rate for SO_2 would be 425 tonnes per day. If the two older (three stage) Claus units were operated to the maximum capacity when the Sulfreen was down, and all else was operating, then the SO_2 emission rate would be about 345 tonnes per day. It would seem appropriate, then, to schedule Sulfreen unit shutdowns when the hydrocrackers and/or hydrotreaters and/or one coker is down.

Another point of interest is that additional expansion beyond the applied for rate, if it followed the same configuration, would have the same effect on emissions. That is to say, if "new" bitumen were to be fed to a low conversion LC-Finer unit and the resulting residue fed to the Fluid Cokers, and the requisite Sulfreen (or equivalent) tail gas clean-up capacity added, SO_2 emissions would be slightly reduced, as would heavy metal emissions. This would apply up to the point where all the feed to the Fluid Cokers is LCF residue, or approximately 365,000 barrels per stream day of bitumen, or 24 per cent beyond the applied for capacity. In the writer's opinion, additional expansion, beyond debottlenecking of the applied for rate, is not too likely because of a limitation on economically mineable oil sands reserves, unless the bitumen comes from other leases.

3.5.2 PARTICULATES

Emission of particulates occurs from the main stack, however the origin of the overwhelming majority of this material is the Fluid Coker, via the burner.

Fluidization of solids is a turbulent activity. In fact its advantage in efficiency of heat and mass transfer is an artifact of the turbulence. There are a lot of collisions between the coke particles, and some lead to fracture and the formation of fines. However it is Consultant's opinion that by far the greatest source of coke fines is attrition steam. This steam is injected into the reactor fluidized bed at supersonic velocity to agitate the bed in a violent manner in order to break-up larger particles and thus control particle size. The reason for this practice is that if the average size of the circulating particles becomes too great fluidization becomes impaired and operation is jeopardized.

Smaller coke particles, or fines, may leave the system only from the burner. Those which exit the reactor into the scrubber are returned in the recycle stream. The product coke stream goes through an elutriator, which is a vessel where a counter-current flow of steam removes the fines and carries them back into the burner. The burner is equipped with two stage cyclones which retain the bulk of all particles above a certain diameter, the break point is probably about fifty microns.

Thus there is a flow of coke dust, as it were, carried from the burner into the CO boiler by the flue gas stream. The mass rate of flow of this material has been measured by an outside contractor. The average weight of particulates from the burner, to the CO boiler, is estimated at 6550 kilograms per stream hour. In the CO boiler, combustible gases in the flue gas stream, namely carbon monoxide, methane, hydrogen sulphide and carbonyl sulphide are burned, but it is felt

that the particulates pass through relatively uncombusted.

At the exit of the CO boiler there are the electro-static precipitators (ESP's) which capture the bulk of the particulates and drop them into bins from whence they are automatically removed, slurried in water, combined with the slurried fluid coke product, and transported to the coke stockpile area. The same contractor who measured the rate of particulate carryover into the CO boiler also measured the efficiency of the ESP's which turns out to be 98.1 per cent. That is to say that of the particulates which enter the CO boiler, 1.9 weight per cent are carried into the atmosphere, and thence the environment, in the flue gas.

The emitted particles, as might be expected, are the smallest, or finest of those carrying over into the CO boiler, and they contain a somewhat lower proportion of heavy metals. As can be seen in Figure 3.7, after the CAP program is complete, SCL forecast that 125 kilograms per hour of particulates are emitted from the ESP's, containing 0.12 and 0.04 kilograms per hour respectively of vanadium and nickel. Figure 3.8 predicts that after Expansion the particulates will be reduced to 107 kilograms per hour and the vanadium and nickel to 0.08 and 0.03 kilograms per hour respectively. SCL's rationale for reduced particulate emissions after expansion is that the amount of coke burned is reduced, thus vapour velocity in the burner is diminished, which in turn brings down solids carryover. This effect had been confirmed by the licensor. However it is Consultant's feeling that the situation may be more complex than suggested, and it is felt to be safer to assume that particulate emission will be unchanged before and after Expansion. It is easily demonstrated, however, that the content of nickel and vanadium is lower, thus the emission of these potentially inimical heavy metals will be reduced.

Consultant has studied the Syncrude Canada Ltd Environmental

Research Monograph 1984-2, "A Study of Metallic Emissions from the Main Stack at Syncrude's Mildred Lake Plant" with great care. It is the report of a project to measure solid emissions and analyze them, undertaken by a research consulting contractor. This was the occasion that the particulate emission rate of 3.0 tonnes per day rate was found, as was the standard deviation of 0.62 tonnes per day. In addition, contractor stated that "additional uncertainties warranted an increase in the measured standard deviation to 0.87 tonnes per day". Consultant has elected to apply that increased standard deviation on the upside only, as it does not make much physical sense on the downside, and plot a frequency distribution curve for particulate emissions which is seen in Figure 3.10 where the daily rates range from 1.5 to 5.7 tonnes. The ninety-five per cent confidence level is at 4.5 tonnes per day, or less. The allowable emission rate for the area is 0.20 grams per kilogram of flue gas. 4.5 tonnes per day works out to 0.077 grams per kilogram. The ninety-nine per cent confidence level is 5.7 tonnes per day, or 0.10 grams per kilogram, just half the allowable. However if from time to time, for whatever reason, the operating efficiency of the ESP's should deteriorate, the particulate emission rate will increase accordingly.

3.5.3 HEAVY METAL EMISSIONS

In the above mentioned monograph 1984-2, each of the particulate samples were analyzed for twenty-six metals. The ones of special interest were vanadium, nickel and lead. Consultant analyzed these data and concluded that the emission rates of particulates and heavy metals were mutually independent. Also, the metals were apparently independent one, from another, with the exception of vanadium and nickel which maintained a fairly constant ratio one to another, averaging about 3.3.

Accordingly, in order to plot emission frequency curves for these heavy metals, a Monte Carlo simulation was undertaken. The particulates were set at the average rate from the Monograph for Pre-CAP and at the rate estimated by SCL Post-Expansion. However, the origin of the vanadium, nickel and lead is the bitumen, and a portion of these metals are deposited on the LCF catalyst. This will be discussed in greater detail later in this section, but the net result is a lower proportion of these substances in the fluid coke product and thence in the particulates. Thus while the particulate emission rate may be unchanged, the percentage content of heavy metals is reduced, resulting in a significant reduction in emission of heavy metals.

The emission frequency curves for vanadium, nickel and lead are seen plotted in Figures 3.11, 3.12 and 3.13 respectively. The two curves, in each case, are for pre-CAP and post-Expansion. Table 3.3, below, lists some statistical data.

TABLE 3.3

HEAVY METAL EMISSIONS DATA

	MEAN kg/day	STD DEVN kg/day	95% CONF kg/day	99% CONF kg/day
VANADIUM				
pre-CAP	2.79	1.04	4.96	6.26
post-Expans	1.97	0.79	3.65	4.59
NICKEL				
pre-CAP	0.86	0.37	1.49	1.88
post-Expans	0.59	0.22	1.10	1.51
LEAD				
pre-CAP	0.32	0.21	0.81	0.97
post-Expans	0.23	0.15	0.57	0.67

In addition to generating the particulate emission graph, Consultant undertook to trace clay and heavy metals through the system by the computer model, as a check against the measured rates.

The first premise is that all clay and heavy metals stay with the heaviest portion of the bitumen. Clay and heavy metals contained in the LCF feed undergo different fates. The clay is unaffected and ends up in the LCF residue which is fed to the Fluid Cokers. A portion of the heavy metals, on the other hand, are retained on the LCF catalyst surface. Nickel is sixty per cent absorbed and vanadium seventy per cent.

The next premise is that all clay and heavy metals in Fluid Coker feed end up in the product coke and fines, and both of these have the same ultimate composition. In Table 3.4 the calculation is traced. Coke yield is on a ash and metal free basis. The computer simulation estimates elemental composition of the coke. The sulphur level is fairly accurately known, but the others not so well. To the daily weights of carbon, hydrogen, sulphur, nitrogen and oxygen from the simulation; the mass rates of clay, vanadium and nickel have been added. Taking a particulate rate of slightly over 3000 kilograms per day, the content of heavy metals has been calculated, as if the composition of particulates were the same as product coke.

In Table 3.5 these results are compared with data from the monograph 1984-2. Examining the figures under the two columns "average" and "base" it is seen that the heavy metals content of the particulate emissions is about half what it theoretically might have been, if they were the same composition as fluid coke.

The probable explanation is an interesting one. As one part of their study, the scientific contractor separated some of the particulates into different size ranges at the time of

capture. It was found that the distribution is what is called "bi-modal", that is to say it fell into two distinct groups, with very little between them, one was about six to ten microns in diameter, and the other averaged about 0.1 microns across. The group with the larger diameter comprised fifty to seventy per cent by weight of the total mass captured. This, by the way, is a common phenomenon with air borne particulate matter. The smaller sized groups, up to half the samples, had little or no vanadium, nickel or lead in it. It seems likely that the ESP's had small effect on this very fine material, but did operate on the larger, heavy metal containing fractions.

It is rather complicated, however, an effort has been made to condense the massive amount of data into Table 3.6. The salient feature is that the very finest material, comprising from 26 to 38 per cent of the particulates contains no silicon, alumina, vanadium and little nickel. The only non-trivial amounts of metals determined in this very fine fraction are sodium, and some iron. The coarser fraction collected is much closer in composition to fluid coke product, the vanadium content ranging from 1600 to 2300 ppm, for example. At any rate, it does seem that if additional, external reduction of particulate emission was to be undertaken, it would catch the larger particles containing the heavy metals.

The one product coke analysis available (seen in Table 2-1, page 2-4) was on a somewhat different basis, clay not being identified as such while "ash" was determined. In comparing this analysis to the result calculated in this study for pre-CAP, in Table 3-4, carbon was very close, while the actual determination had lower hydrogen content, higher nitrogen, and identical sulphur. Oxygen plus ash added up to be close to the study clay plus oxygen. Vanadium and nickel at 0.15 and 0.05 respectively were not far from the study values of 0.18 and 0.057.

This study may have higher metal values as the computer model had slightly higher levels of nickel and vanadium at 75 and 250 weight parts per million, respectively, compared to SCL determinations of 70 and 230.

In the final analysis, the contractor's measurements of particulate emissions and determination of the heavy metals content therein should be considered the most accurate assessment currently available.

3.6 CATALYST

In operating the ebullated bed hydrocracker, spent catalyst is withdrawn daily and fresh catalyst is added as a replenishment. The amounts of this material become substantial.

The major agent leading to the deactivation of the catalyst is accumulation of nickel and vanadium on its surface preventing access by hydrocarbon molecules to the active sites. In addition, accumulation of carbon on the catalyst surface has a milder deactivating effect.

For low conversion operation, typical catalyst addition rates are in the range 0.15 to 0.20 pounds per barrel of feed to the unit. Assuming that the rate is 0.16 pounds of catalyst make-up per barrel of feed, and further assuming that it is a nickel molybdenum type of catalyst with 2.5 weight per cent nickel on the fresh material, calculations lead to the results seen in Table 3.7 on the following page.

In considering the disposition of this material, Syncrude Canada Ltd are examining a number of options, including metal reclamation. It can be seen that there are very interesting amounts of nickel and vanadium on the spent catalyst.

TABLE 3.7

CATALYST ADDITION & WITHDRAWAL

	CAP PROGRAM	EXPANSION
Fresh catalyst, lb/day	8,000	34,100
Spent catalyst, lb/day	17,460	74,430
Partial composition of spent catalyst		
Nickel, wt per cent	5.0	5.0
Vanadium, wt per cent	18.0	18.0
Carbon, wt per cent	23.0	23.0
Sulphur, wt per cent	11.0	11.0

TABLE 3.1

COMPARISON of STUDY CALCULATIONS to APPLICATION

all figures thousands of barrel per calendar day
(unless otherwise stated)

	BASE - PRE CAP		POST CAP		EXPANSION		DIFFERNCE
	STUDY	APPL'N	STUDY	APPL'N	STUDY	APPL'N	CAP->EXPN
Athabasca bitumen feed	148.2	148.2	188.8	188.8	265.5	265.5	76.7
side stream to ht	7.3	7.3	11.3	11.5	15.9	15.9	4.6
mid bitumen to ht's							
topped bitumen to lcf & fk	140.9	140.9	177.5	177.3	249.6	249.6	72.1
975+ bitumen to high conv'n							
bitumen to lc-finer			45.0	45.0	191.8	191.8	146.8
lcf liquid to ht			27.3	25.8	112.2	114.7	84.9
lcf pitch to coker			18.5	18.5	81.0	80.5	62.5
total lcf liquid			45.8	44.3	193.2	195.2	147.4
lc-finer resid to coker			18.5	18.5	81.0	80.5	62.5
bitumen to coker	140.9	140.9	132.5	132.3	57.8	57.8	-74.7
total fluid coker feed			150.9	150.8	138.8	138.2	-12.1
fk liquid to ht	115.5	112.6	122.9	122.9	109.7	108.1	-13.2
975+ bitumen to high conv'n							
high conv'v liq to ht's							
high conv'n pitch							
side stream to hydrotr's	7.3	7.3	11.3	11.5	15.9	15.9	4.6
mid bitumen to hydrotr's							
lc-finer liquid to hydrotr's			27.3	25.8	112.2	114.7	84.9
coker liquid to hydrotr's	115.5	112.6	122.9	122.9	109.7	108.1	-13.2
high conv'v liq to ht's							
total hydrotreater feed	122.8	119.9	161.5	160.2	237.8	238.7	76.3
sco product	123.3	120.8	163.5	162.5	243.8	244.1	80.3
sco product, vol% bit	83.2	81.5	86.6	86.1	91.8	91.9	104.7
burned coke, tonnes/cd	1243.1	1229.0	1221.2	1070.0	1130.1	1143.7	-91.1
product coke, tonnes/cd	2779.5	2921.0	3300.3	3400.0	3749.9	3500.0	449.6
coke fines, tonnes/cd	125.9		140.0		140.0		0.0
gross coke, tonnes/cd	4148.5	4150.0	4661.5	4470.0	5019.9	4643.7	358.4
high conv'n pitch, t/cd							
total residue, tonnes/cd	4148.5	4150.0	4661.5	4470.0	5019.9	4643.7	358.4
sulphur product, tonnes/cd	701.4	769.1	1037.4	1052.4	1651.9	1700.0	614.5
total chem hydrogen, SCF/Bbl	878	945	1184	1208	1806	1740	

TABLE 3.2

COMPARISON of STUDY & APPLICATION SULPHUR BALANCES

all figures in tonnes per stream day

	BASE - PRE CAP		POST-CAP		EXPANSION		DIFFERNCE
	STUDY	APPL'N	STUDY	APPL'N	STUDY	APPL'N	CAP->EXPN
	t/sd	t/sd	t/sd	t/sd	t/sd	t/sd	t/sd
ATHABASCA BITUMEN	1323.4	1318.3	1635.2	1636.5	2299.3	2302.6	664.1
VGO CATCH-UP		62.6		62.1		60.4	
		1380.9		1698.6		2363.0	
LCF FEED			407.9	405.5	1738.8	1728.4	1330.9
LCF H2S			272.6	255.1	1142.5	1119.9	870.0
LCF LIQUID TO HT's			34.0	42.8	147.0	155.4	113.0
LCF PITCH TO FK			101.4	107.6	449.2	453.1	347.9
			407.9	405.5	1738.7	1728.4	1330.8
LCF PITCH TO FK			101.4	107.6	449.2	453.1	347.9
BITUMEN TO FK	1302.2	1291.0	1201.0	1192.2	523.6	520.5	-677.4
TOTAL			1302.4	1299.8	972.8	973.6	-329.5
FK H2S	209.4	243.2	184.1	206.1	107.8	108.5	-76.3
FK LIQUID TO HT's	716.3	689.1	718.2	697.7	479.9	520.8	-238.3
FK COKE PRODUCT	252.2	252.5	283.3	292.0	287.7	259.5	4.4
FK COKE FINES	11.4		12.0		10.7	-	-1.3
BURNED COKE	112.8	106.2	104.8	104.0	86.7	84.8	-18.1
975+ TO HIGH CONVERSION							
HIGH H2S							
HIGH LIQ TO HT's							
HIGH PITCH							
SIDE STREAM TO HT	21.2	27.3	26.3	38.8	36.9	53.7	10.6
MID BITUMEN TO HT's							
LCF LIQUID TO HT's			34.0	42.8	147.0	155.4	113.0
FK LIQUID TO HT's	716.3	689.1	718.2	697.7	479.9	520.8	-238.3
HIGH LIQ TO HT's							
CATCH-UP VGO		62.6		62.1		60.4	
TOTAL	737.5	779.0	778.5	841.4	663.8	790.3	-114.7
HT H2S	699.4	740.7	729.7	794.1	632.8	759.5	-96.9
HT PRODUCTS TO SCO	38.2	38.3	47.4	47.3	29.8	30.8	-17.6
LCF H2S TO CLAUS			272.6	255.1	1142.5	1119.9	870.0
HIGH H2S TO CLAUS							
FK H2S TO CLAUS	209.4	243.2	174.1	206.1	107.8	108.5	-66.3
HT H2S TO CLAUS	699.4	740.7	729.7	794.1	632.8	759.5	-96.9
TOTAL	908.8	983.9	1176.4	1255.3	1883.1	1987.9	706.7
PRODUCT SULPHUR	877.0	949.5	1152.9	1230.2	1845.5	1948.1	692.6
CLAUS TAIL GAS	31.8	34.4	23.5	25.1	37.7	39.8	14.2
BURNED COKE	112.8	106.2	104.8	104.0	86.7	84.8	-18.1
CLAUS TAIL GAS	31.8	34.4	23.5	25.1	37.7	39.8	14.2
TOTAL EMISSIONS	144.6	140.6	128.3	129.1	124.4	124.6	-3.9
EMISSION S02	289.2	281.2	256.6	258.2	248.8	249.2	-7.8
EMISSIONS t/kbbl	1.58	1.54	1.22	1.23	0.94	0.94	

TABLE 3.4
SYNCRUDE - CLAY & HEAVY METALS BALANCE

	BASE CASE			CAP - PROGRAM			EXPANSION		
	CLAY kg/day	VANADIUM kg/day	NICKEL kg/day	CLAY kg/day	VANADIUM kg/day	NICKEL kg/day	CLAY kg/day	VANADIUM kg/day	NICKEL kg/day
bitumen in	294092	7352	2206	337162	8429	2529	474083	11852	3556
bitumen to lcf				85484	2137	641	364365	9109	2733
lcf feed to fk				85484	620	282	364365	2642	1202
bitumen to fk	294092	7352	2206	251684	6292	1888	109718	2743	823
lcf feed to fk				85484	620	282	364365	2642	1202
total to fk	294092	7352	2206	337168	6912	2170	474083	5385	2025
gross coke, tonnes/day ash & metal free basis		5122			5179			5578	
sulphur in gross coke, t/d		376.5			400.1			385.2	
burned coke, tonnes/day		1535			1357			1256	
sulphur in burned coke, t/d		112.8			104.8			86.7	
net coke & fines		kg/day	weight per cent		kg/day	weight per cent		kg/day	weight per cent
carbon		3118700	80.15		3310784	79.42		3781784	78.73
hydrogen		153185	3.94		161722	3.88		188521	3.92
sulphur		263655	6.78		295311	7.08		298468	6.21
nitrogen		36236	0.93		39134	0.94		44017	0.92
oxygen		15198	0.39		15613	0.37		9220	0.19
clay		294092	7.56		337168	8.09		474083	9.87
vanadium		7352.3	0.189		6911.7	0.166		5384.7	0.112
nickel		2205.7	0.057		2169.7	0.052		2025.3	0.042
total		3890625	100.0		4168814	100.0		4803503	100.00
fines only		155492			155538			155511	
particulates		3054.2			3054.2			3054.2	
vanadium		5.772			5.064			3.424	
nickel		1.731			1.590			1.288	

NOTE: Clay is taken to be 1.0 weight per cent of whole bitumen

TABLE 3.5
PARTICULATES and HEAVY METALS EMISSIONS

	ACTUAL DATA - 1984								STUDY DATA THEORETICAL		
	A	B	C	D	E	F	AVERAGE	STD DEVN	BASE	CAP	EXPANSION
particulates - kilograms per day											
total particulates	3507.8	2877.1	3672.0	3516.5	2082.2	2669.8	3054.2	620.4	3054.7	3054.7	3054.2
vanadium	3.871	4.182	2.177	2.851	1.581	2.091	2.792	1.045	5.772	5.064	3.424
nickel	1.348	1.253	0.648	0.864	0.423	0.631	0.861	0.372	1.731	1.590	1.288
lead	0.340	0.553	0.340	0.192	0.295	0.224	0.324	0.207			
weight per cent of total particulates											
vanadium	0.110	0.145	0.059	0.081	0.076	0.078	0.091		0.189	0.166	0.112
nickel	0.038	0.044	0.018	0.025	0.020	0.024	0.028		0.057	0.052	0.042
lead	0.010	0.019	0.009	0.005	0.014	0.008	0.011				

TABLE 3.6

PARTICULATE ANALYSIS BY SIZE RANGE

all figures in micrograms

	TEST A				TEST B				TEST C			
	LARGEST	4 OTHERS	SMALLEST	TOTAL	LARGEST	4 OTHERS	SMALLEST	TOTAL	LARGEST	4 OTHERS	SMALLEST	TOTAL
TOTAL SAMPLE	205300	17230	140600	363000	144700	36224	73610	256000	178750	68500	89670	336000
SILICON	3860	593	*	4500	1590	1015	*	2650	1640	1506	*	3200
ALUMININUM	3100	525	*	3640	1610	889	*	2510	1910	1324	*	3260
IRON	4886	784	122	5790	1580	1259	84	2920	3910	2541	146	6606
MANGANESE	205	23	5	233	48	95	29	172	804	225	14	1040
CALCIUM	524	51	*	642	289	166	*	510	350	204	*	610
MAGNESIUM	224	34	*	275	116	68	*	202	139	89	*	245
SODIUM	595	*	6820	7600	362	290	4480	5200	536	352	3720	4660
TITANIUM	731	64	1	796	263	179	1	442	268	245	1	513
VANADIUM	489	60	*	550	258	100	*	360	286	143	*	432
NICKEL	181	37	16	234	84	63	4	150	340	332	11	683
20 OTHERS	197	*	*	328	90	*	*	252	620	*	*	1040

* indicates below detectable limit in some instances this can be as high as 100 micrograms, but is usually below ten

AVERAGE DIAMETER OF EACH SIZE RANGE, IN MICRONS

LARGEST	6.05
	2.55
	1.89
	0.70
	0.36
SMALLEST	filter

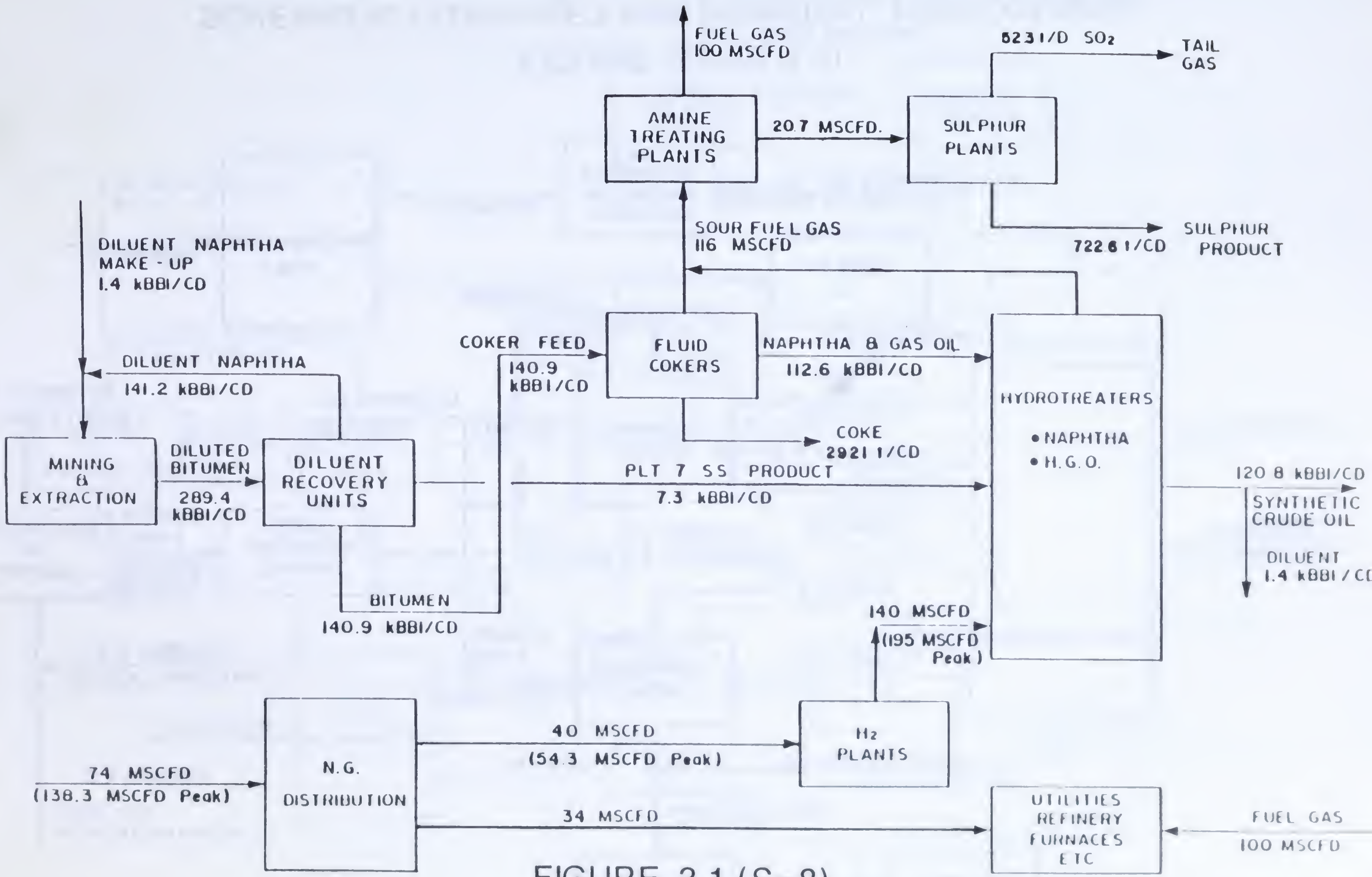


FIGURE 3.1 (S-8)

Figure S-8 Schematic flow sheet for principal hydrocarbon streams of existing Syncrude facilities. Replaces Figure 3.1.1.

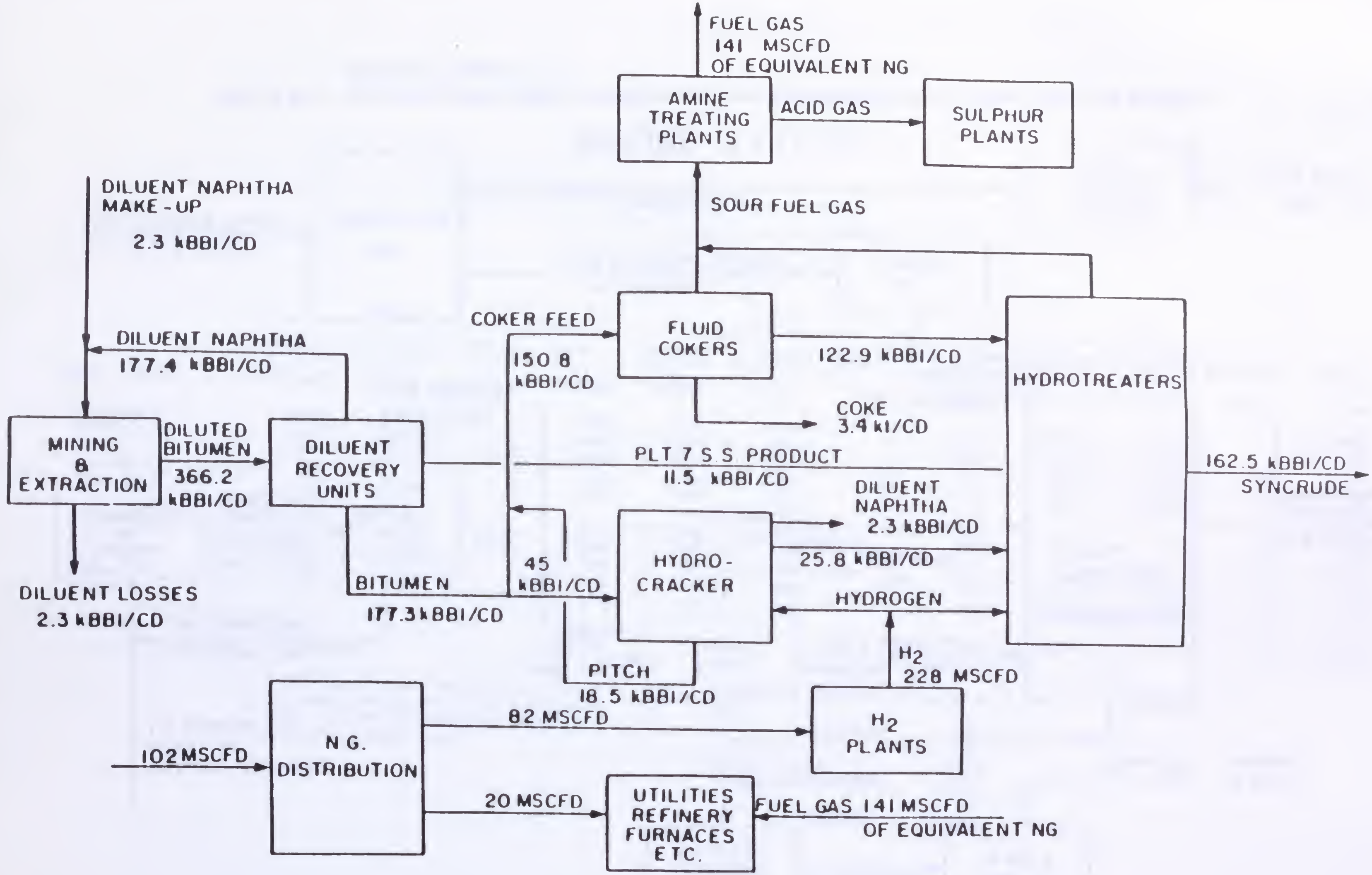


FIGURE 3.2 (3.0.2)
SCHEMATIC FLOWSHEET FOR PRINCIPAL HYDROCARBON STREAMS ANTICIPATED FOLLOWING COMPLETION OF CAP

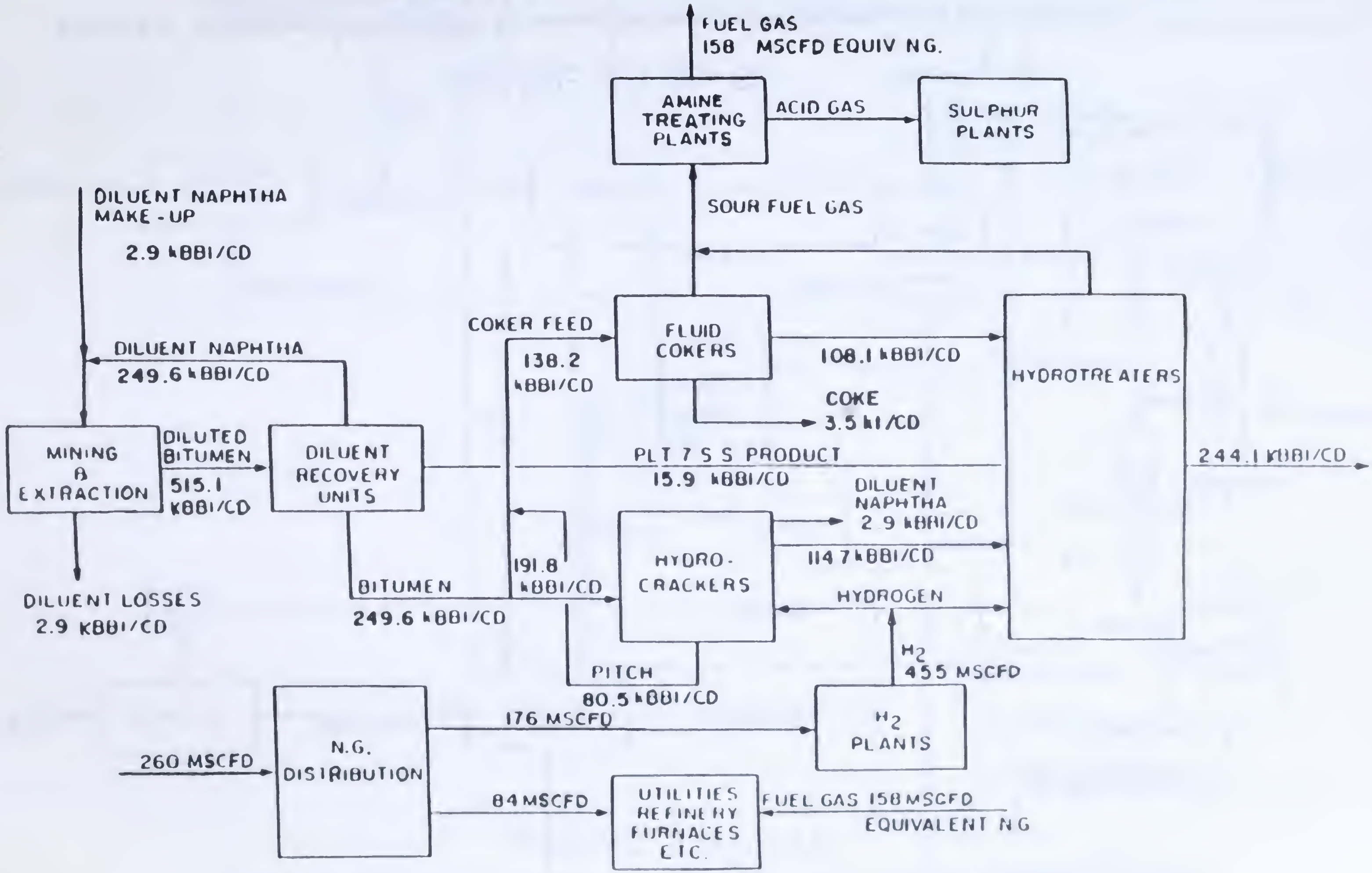


FIGURE 3.3 (4.1.3)

SCHEMATIC FLOWSHEET FOR PRINCIPAL HYDROCARBON STREAMS OF SYNCRUDE FACILITIES FOLLOWING EXPANSION

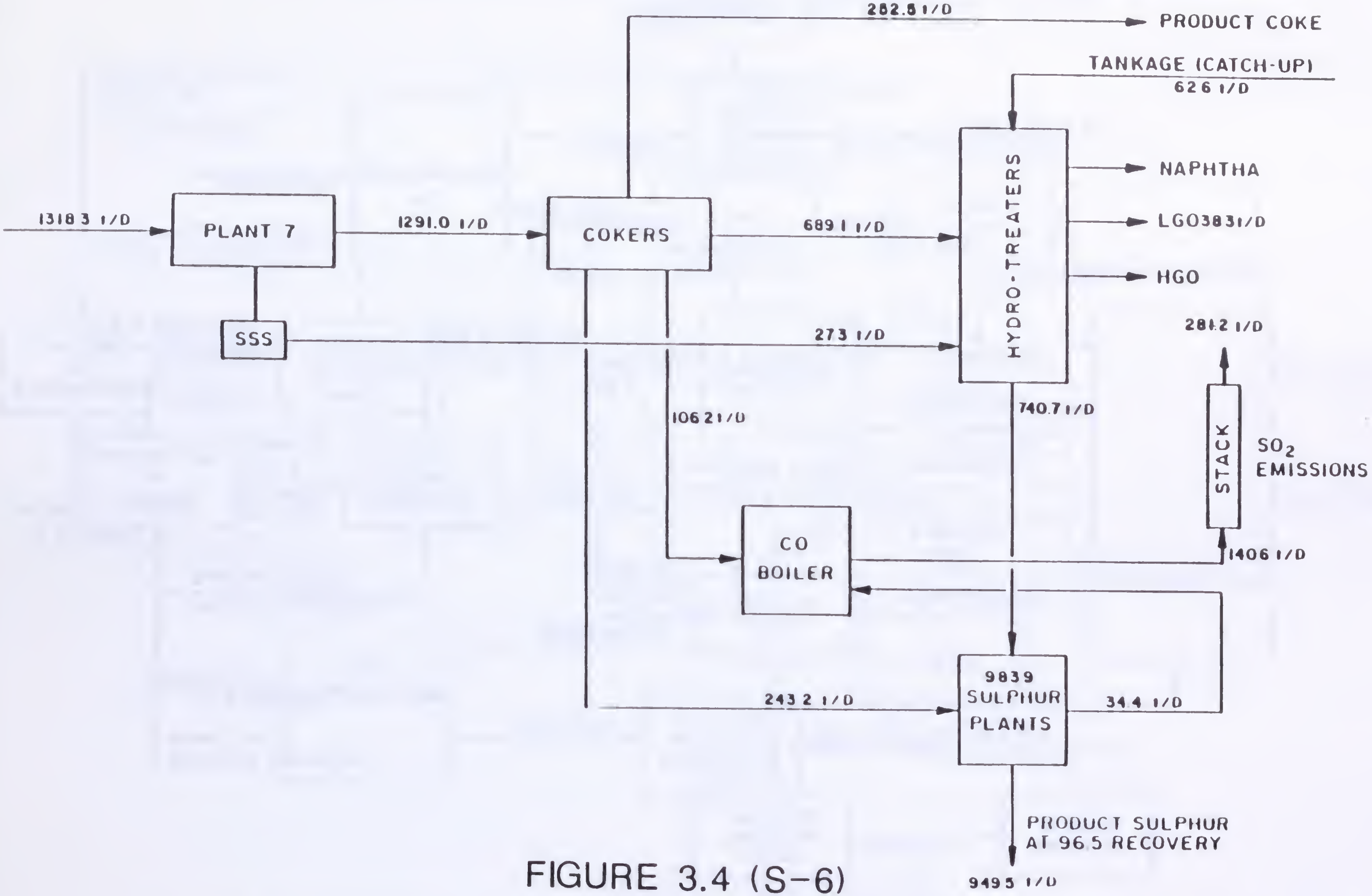


FIGURE 3.4 (S–6)

Figure S-6 Theoretical sulphur balance for existing facilities (maximum stream day basis plus catch-up). Replaces Figure 3.1.3.

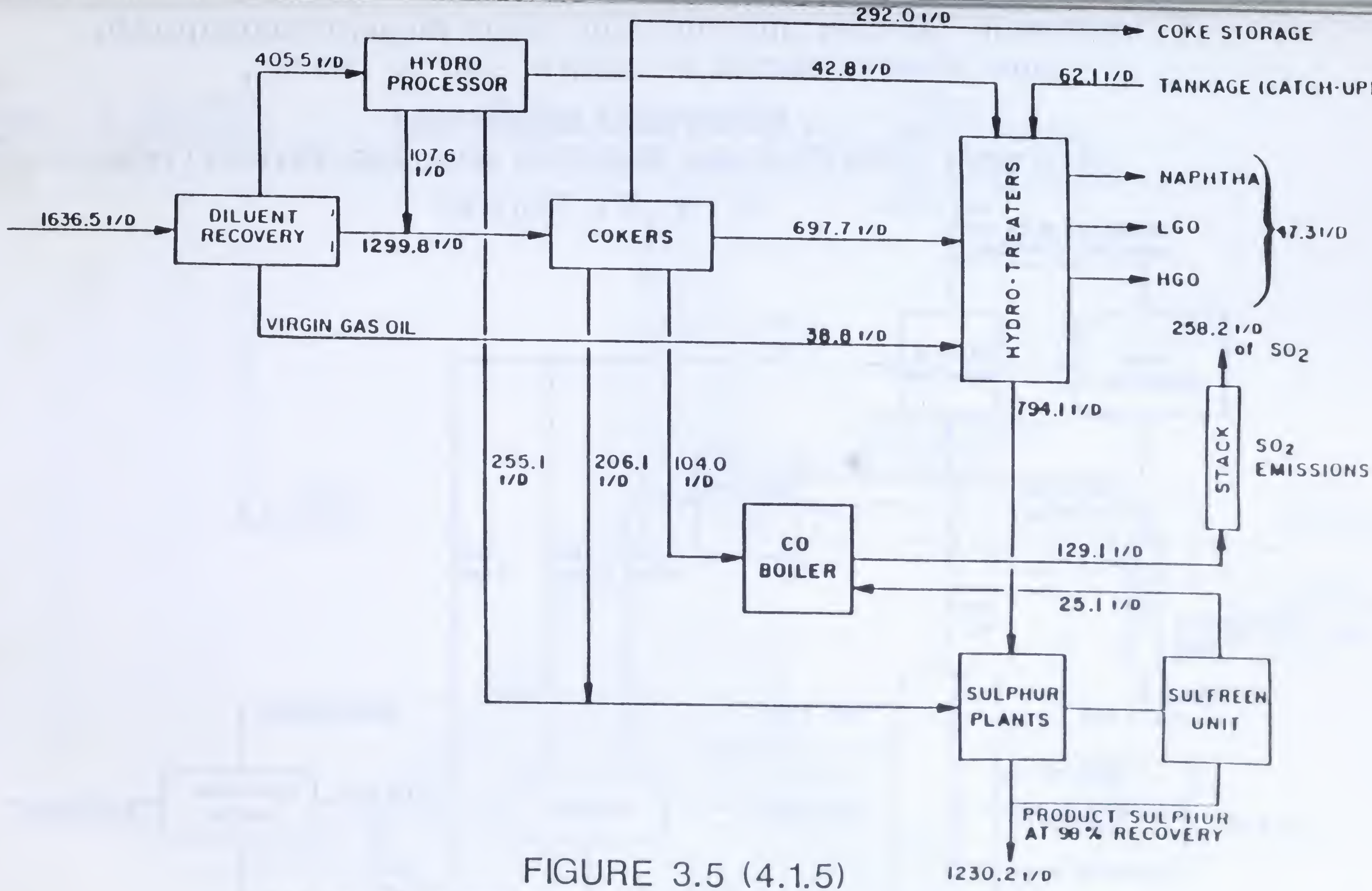


FIGURE 3.5 (4.1.5)

CALCULATED SULPHUR BALANCE FOLLOWING COMPLETION OF CAP*

*Based on 209.8 KBSPD of bitumen charge with hydrotreating running above this rate with tankage drawdown

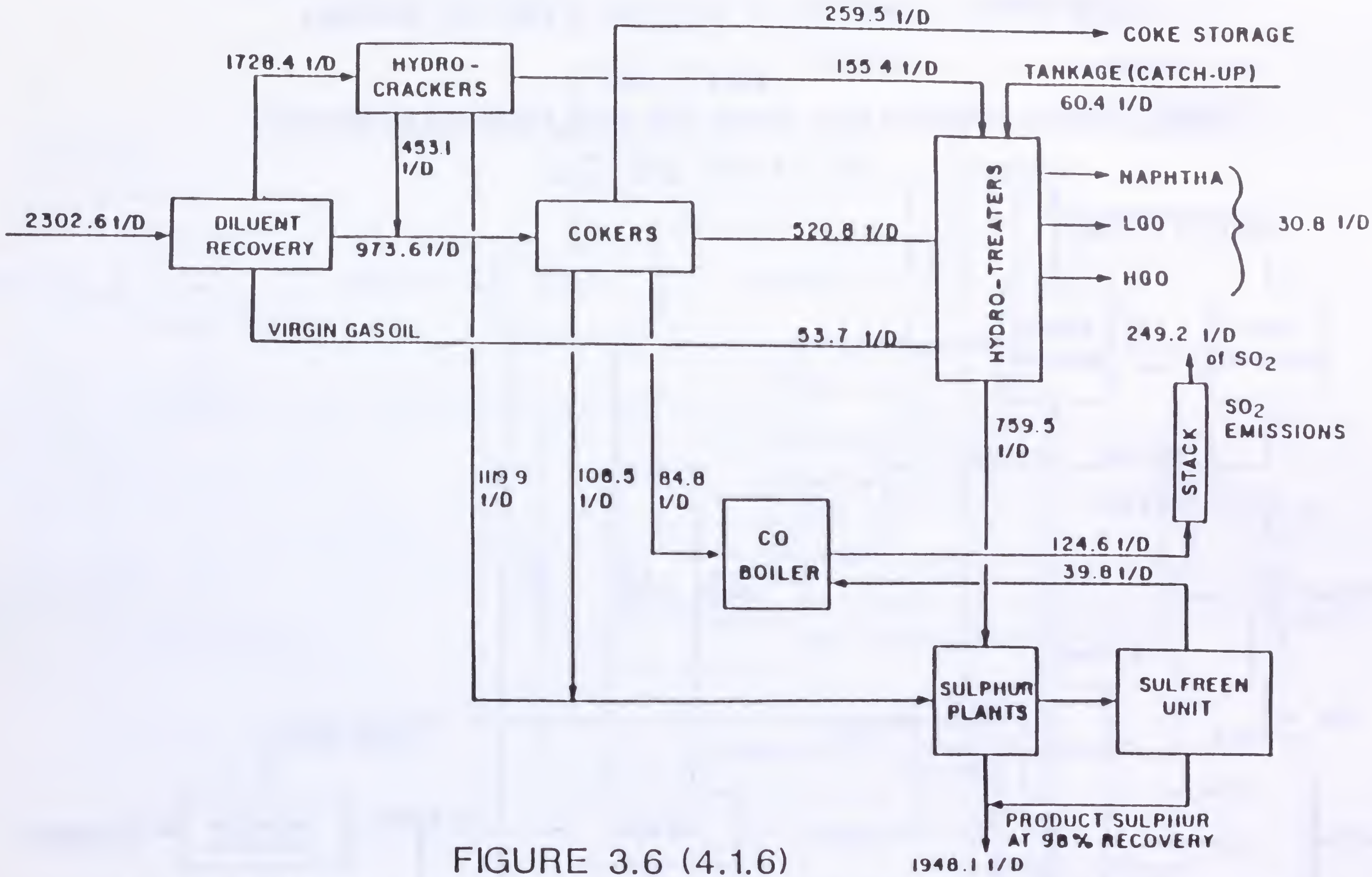


FIGURE 3.6 (4.1.6)

CALCULATED SULPHUR BALANCE FOR SYNCRUDE FACILITIES FOLLOWING EXPANSION *

* Based on 295 KBSPD of bitumen charge with hydrotreating running above this rate with tankage draw down

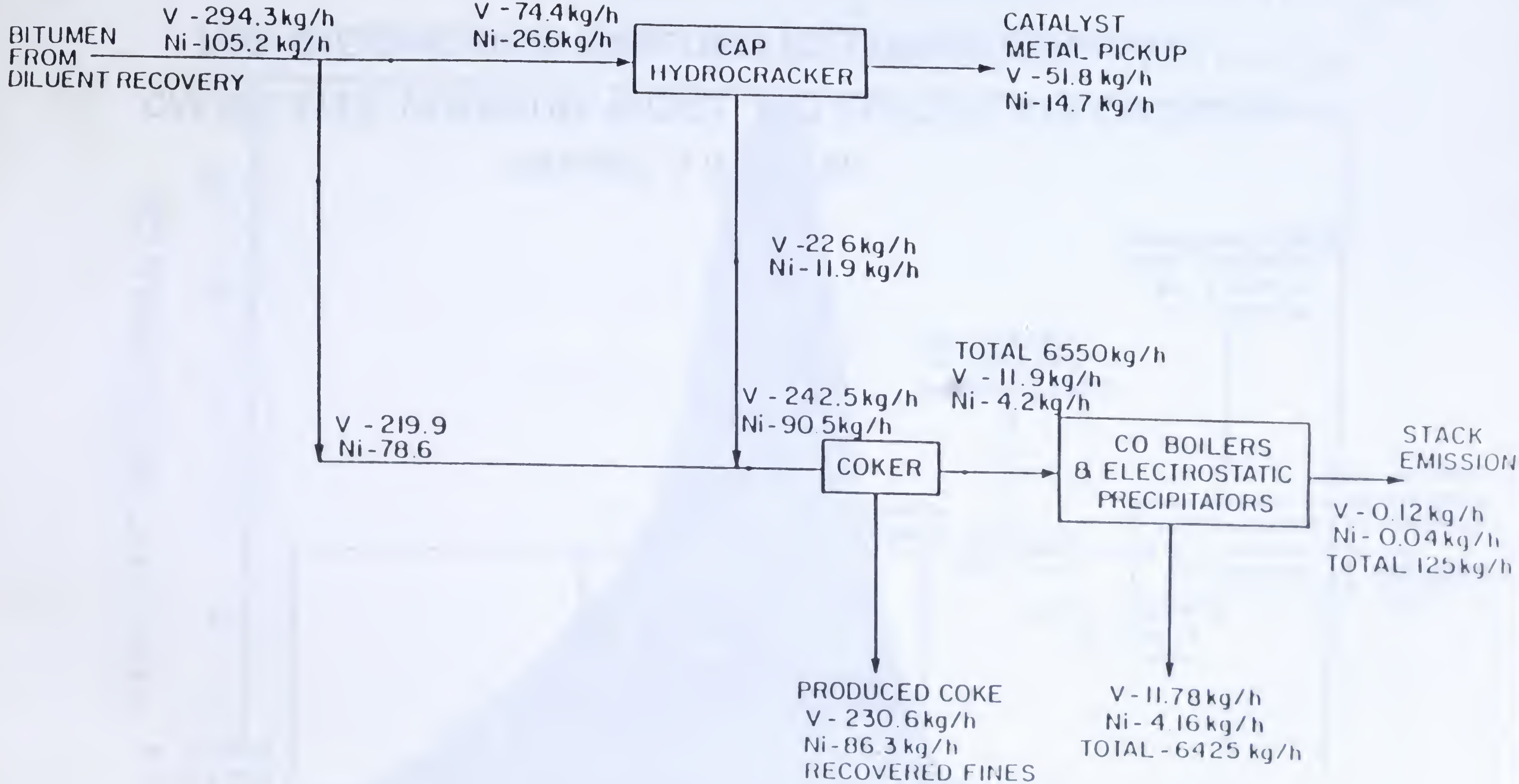


FIGURE 3.7 (4.1.9)

CALCULATED VANADIUM, NICKEL & PARTICULATE EMISSIONS
FOLLOWING COMPLETION OF CAP

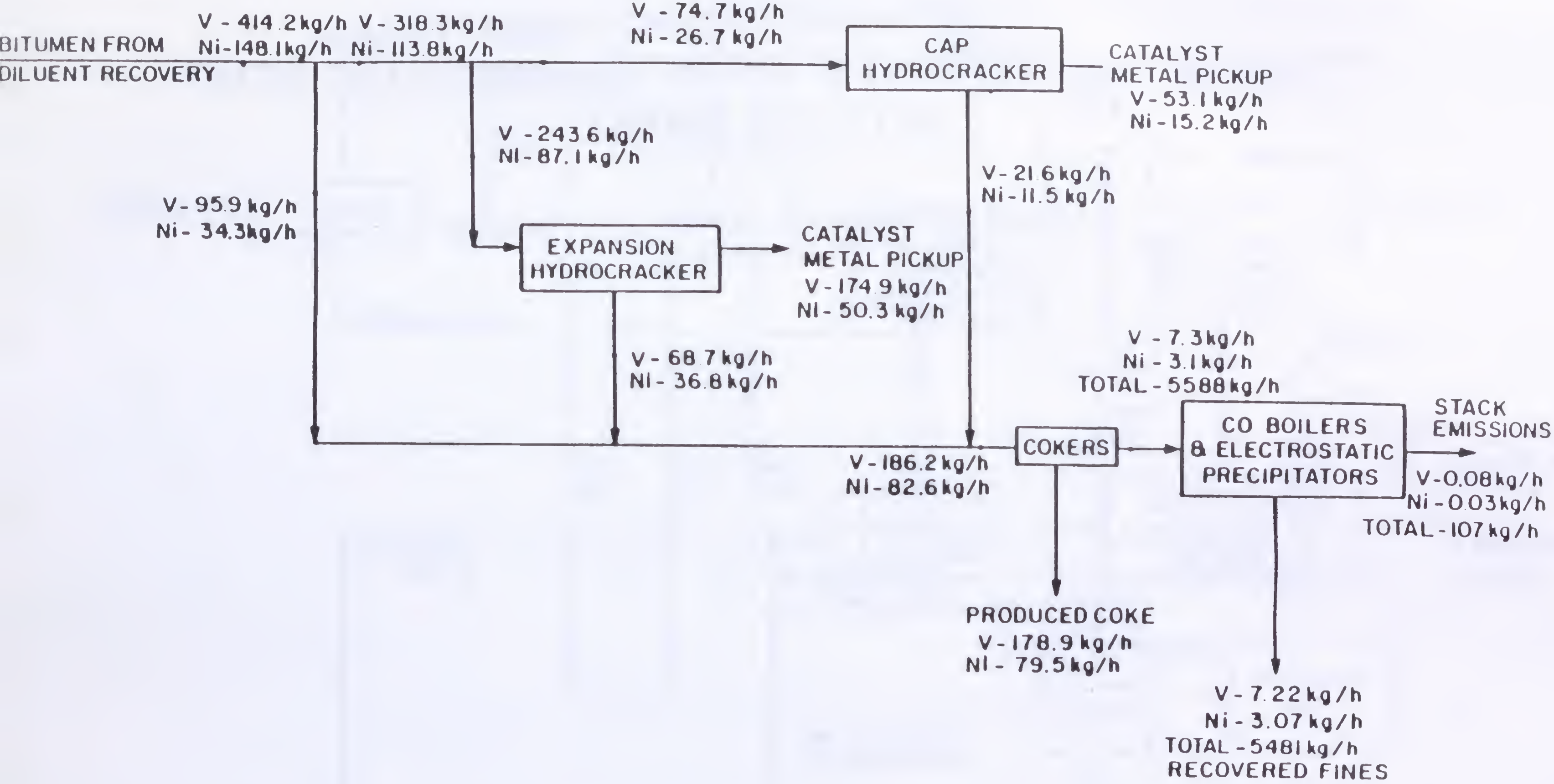
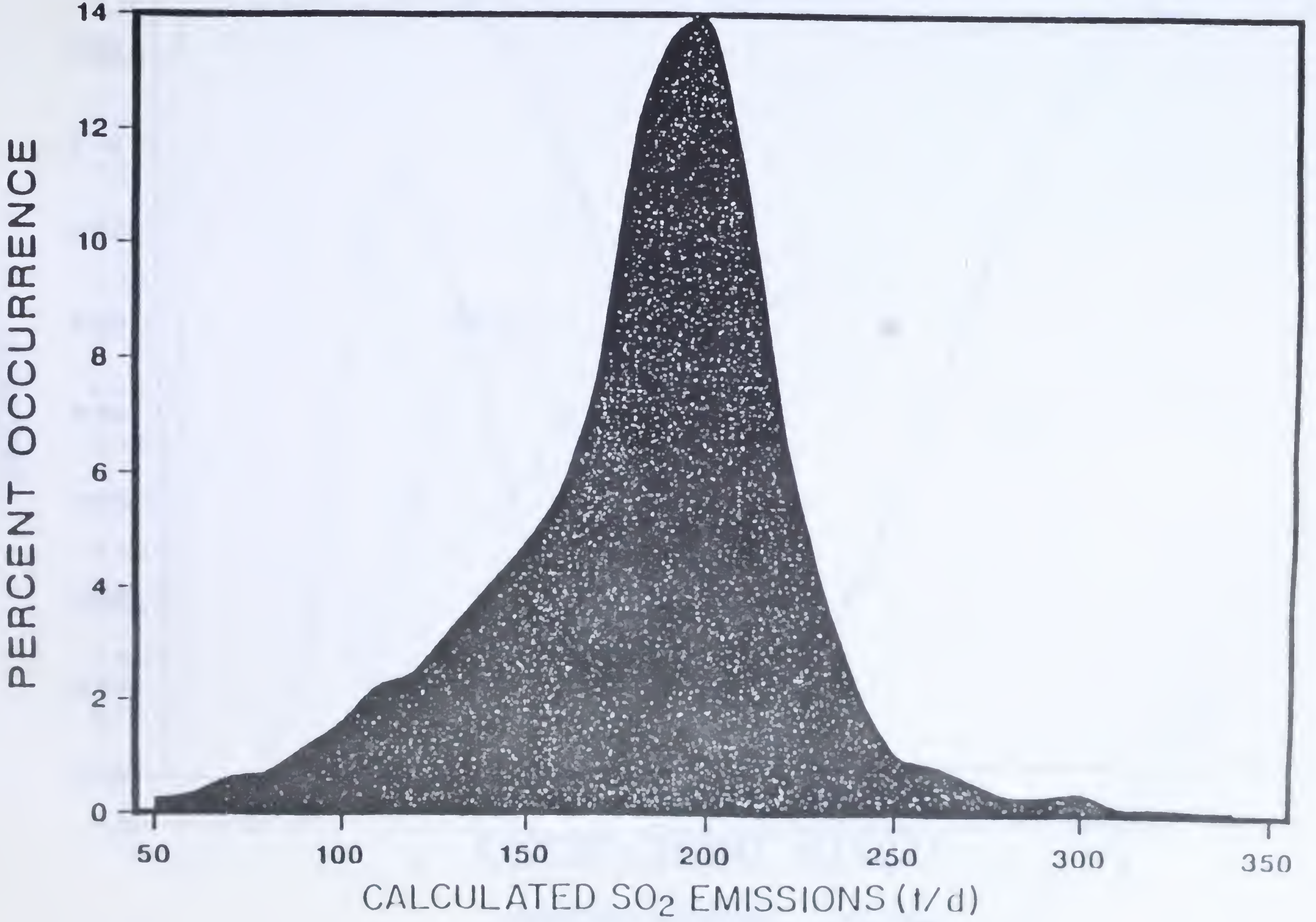


FIGURE 3.8 (4.1.10)

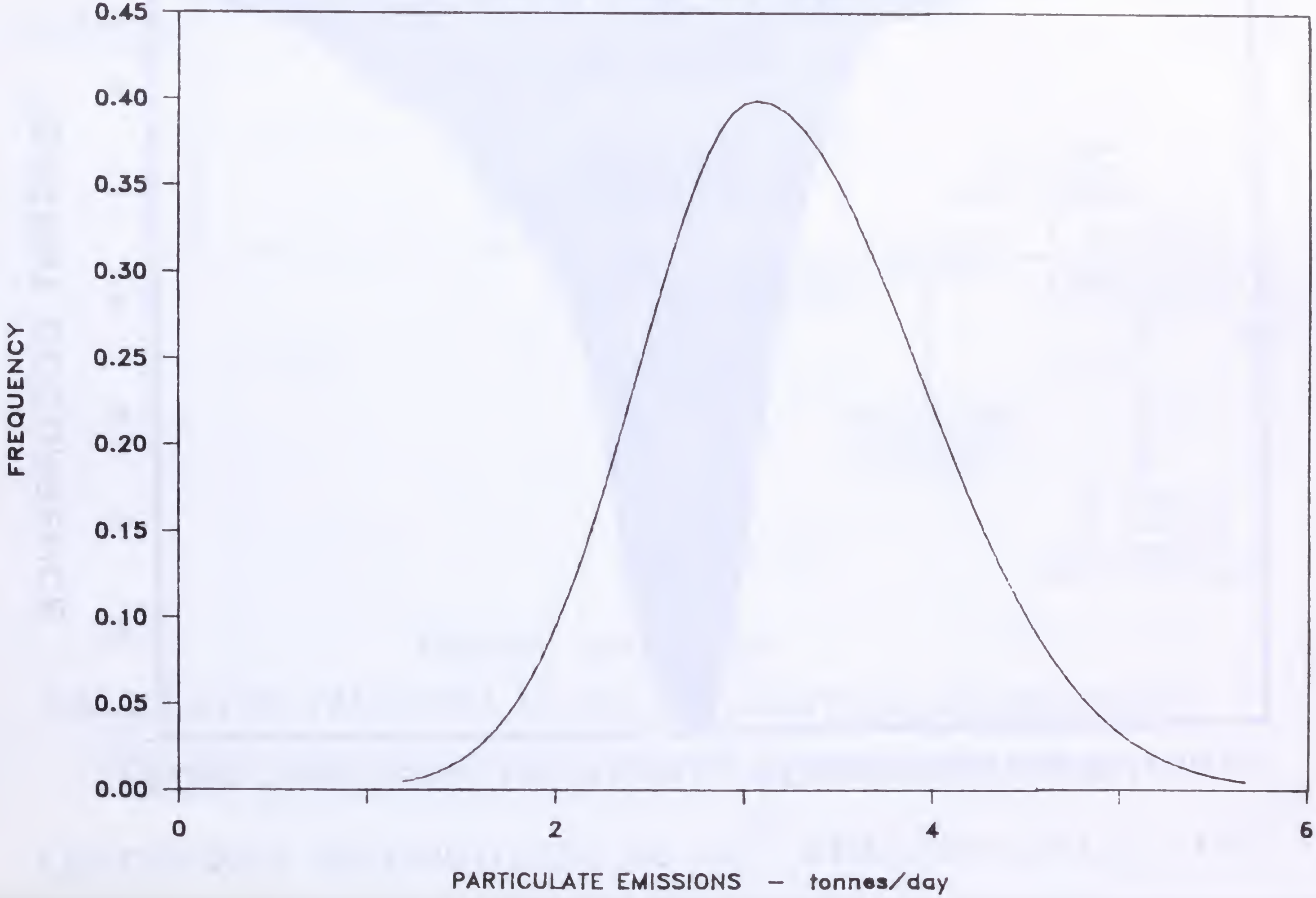
CALCULATED VANADIUM, NICKEL AND PARTICULATE EMISSIONS FOR THE SYNCRUDE FACILITIES FOLLOWING EXPANSION

FREQUENCY DISTRIBUTION OF SO_2 EMISSION RATES (tSO_2/d) FROM SYNCRUDE FACILITIES FOLLOWING EXPANSION



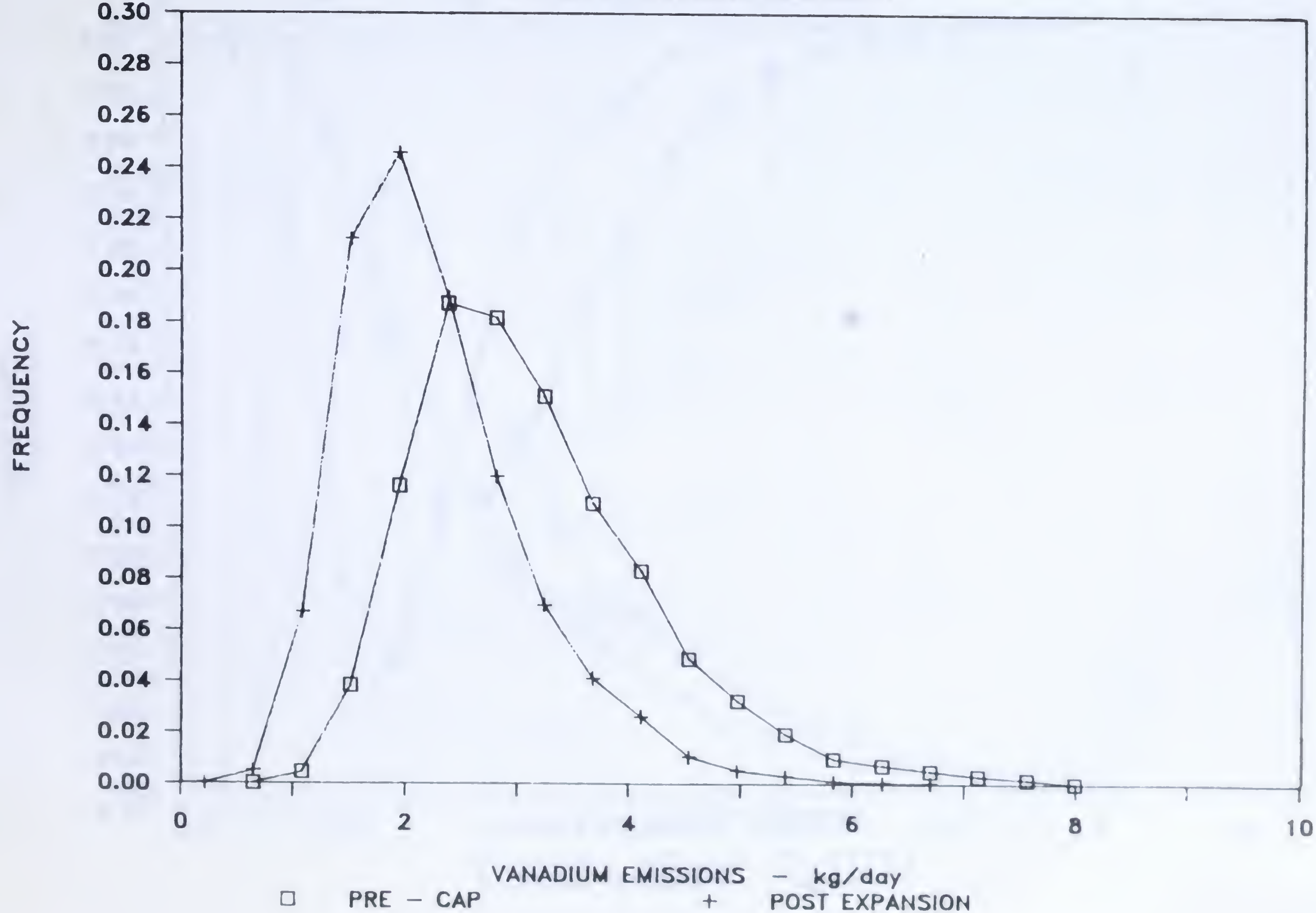
ERCB/SERG STUDY

FIG 3.10 PARTICULATE EMISSIONS



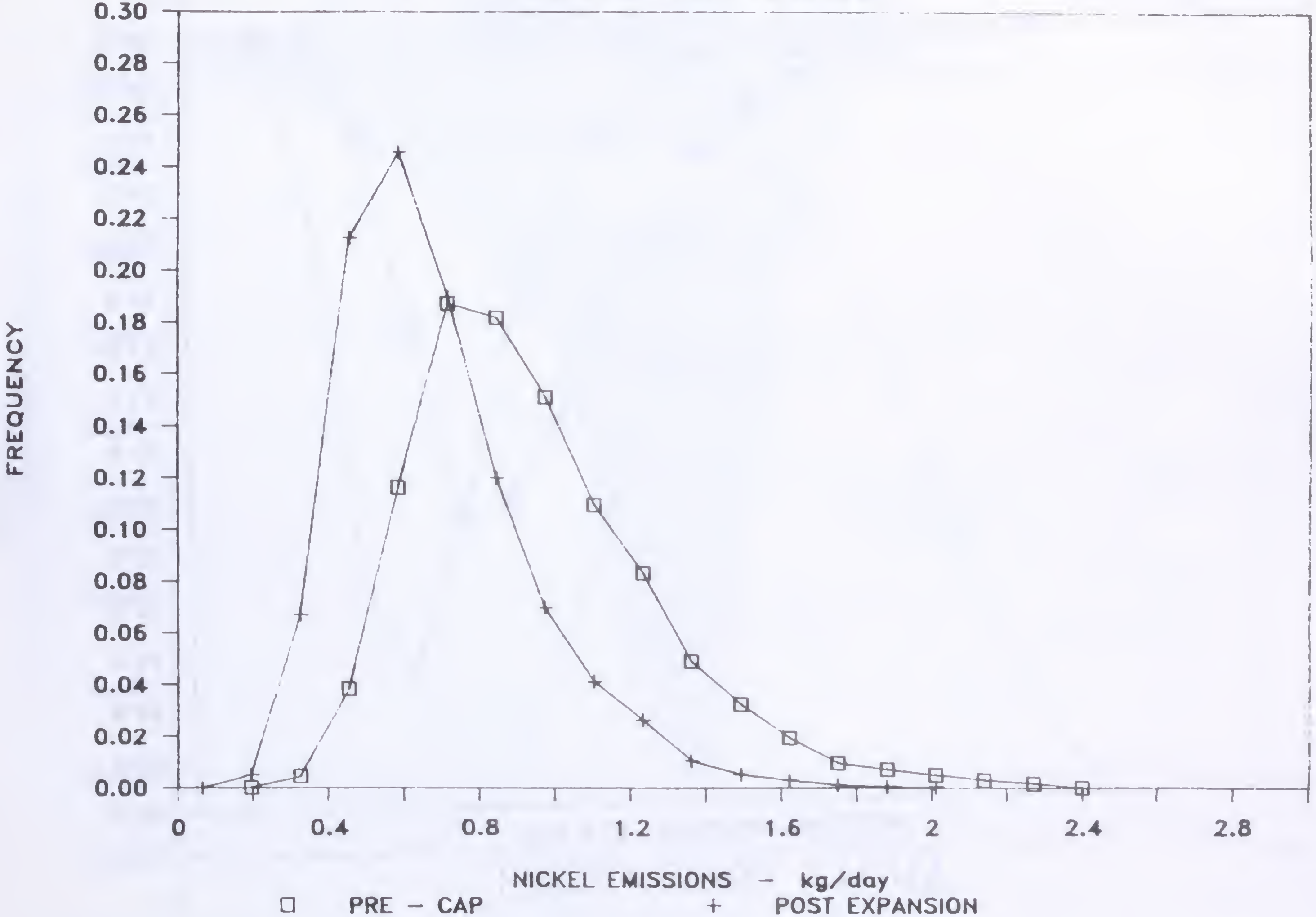
ERCB/SERG STUDY

FIG 3.11 VANADIUM EMISSIONS



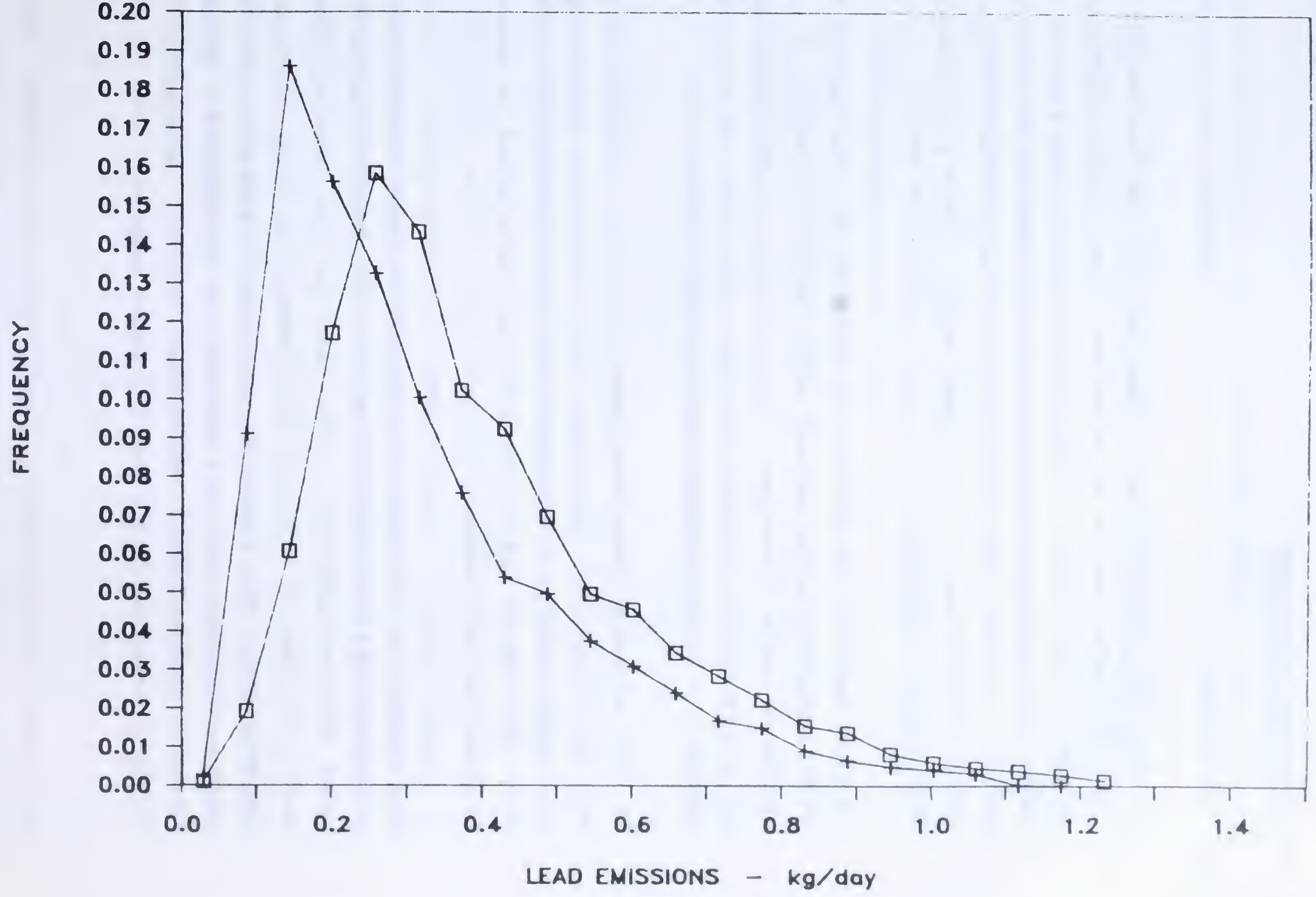
ERCB/SERG STUDY

FIG 3.12 NICKEL EMISSIONS



ERCB/SERG STUDY

FIG 3.13 LEAD EMISSIONS



4.0 EMISSION ABATEMENT

4.1 BACKGROUND

In the previous sections of this work it has been established that the major source of emissions from the SCL installation is the central stack. Through this conduit SO_2 and the heavy metal containing particulates are discharged to the atmosphere. Except for about twenty-five per cent of the SO_2 which originates in the Claus units, these pollutants are from the Fluid Cokers.

In this section two methods of reducing SO_2 and particulates emissions from the stack will be discussed and their estimated costs presented. The objective of this undertaking is to provide an insight into what cost might be incurred to reduce the level of emissions from this source.

It has already been mentioned and will be described in section five, that selecting high conversion hydrocracking technology does not influence the rate of emissions favourably, as long as the Fluid Cokers are maintained in operation at their maximum rate.

The methods to be examined are of the type called Flue Gas Desulphurization (FGD). The data for this assessment are taken from an excellent study done for the Research Management Division of Alberta Environment in 1983 by Dynawest Projects Ltd. The report is entitled "A Review of the Technology Avaliable For the Control of Atmospheric Emissions From Oil Sands Plants" RMD Report 83/19. Hereinafter this shall be referred to as the "Dynawest Report".

4.2 DYNAWEST REPORT

In the introduction to the Dynawest Report, its scope is summarized as follows:

1. Review briefly bitumen extraction and upgrading technologies.

2. Review and update Claus sulphur recovery technologies.

3. Review and update Claus plant tail gas clean-up technologies.

4. Review and update flue gas desulphurization technologies.

5. Review air fluidized bed technologies.

6. Review coke gasification technologies.

7. Review control systems for oxides of nitrogen.

As indicated, after establishing the configuration of a "typical" surface mining oil sands plant, it then proceeds to review the technologies in the noted fields. The plant configuration resembles that of the 1979 ALSANDS application to the ERCB.

Although a lot of processes are reviewed, the depth to which they are assessed is surprising. Particularly the more important ones. Critical design and operating features are noted as well as some comment on advantages and disadvantages.

In each section the processes of interest are described sequentially. Then there is an economic summary comprising

estimated capital and operating costs. Next there is a section on retrofitting with general considerations and notes for specific processes. Finally there are some comments on the applicability of individual processes in an oils sands context.

4.3 PROCESSES

This study will discuss two FGD processes, which are described in the Dynawest Study. It should not be construed in any way that either one is considered superior to the other, or to others not dealt with here, or even that any one of them is the "best" for oil sands surface mining service. The rationale for their selection is that one is the most widely used, and the other has a feature which might be of special interest. The Dynawest Study has been used as the sole source of reference for the two processes.

A developing process, Engelhard's ESR, is too recent to be included in the Dynawest Study. Its advantage is that it yields the captured sulphur as H_2S, easily handled in the Claus units, and, most importantly, has no solid or liquid waste streams. From discussions with the licensor, it seems that it might not be thermodynamically best suited for retrofit at Syncrude as the entire flue gas stream must be reheated to a relatively high temperature where the sulphur is adsorbed, and then cooled back down to its previous temperature. This is expensive to do efficiently. In addition it does not reduce the particulates emissions. Nonetheless, because it has no disposal problem, it should be kept in mind.

4.4 LIMESTONE SLURRY

This FGD process is the most widely applied, and has now had its operating and design "bugs" (of which there were many!) eliminated. It is not an especially forgiving process, but

with the hard won understanding now available, it should be able to function well for any plant which possesses a competent operating staff. It removes ninety per cent of the SO_2 and much of the remaining particulates.

The absorbing medium is a slurry of finely ground limestone. The flue gas, having had particulates removed by electrostatic precipitators (ESP's) is fed to the first stage of the absorber. This is called the quencher section and the flue gas is admitted tangentially and spirals upward through the slurry spray to the further stages. In this section further fly ash removal takes place, the gas is reduced to its saturation temperature and the remainder of the vessel is protected against fly ash excursions.

Passage through a liquid gas separator straightens the flue gas flow to a vertical orientation, whence it passes through further counter-current stages to absorb about ninety per cent of the contained SO_2. The upper level slurry is prevented from entering the quencher area to maintain independent operation of the sections, and protect the upper segments from influxes of fly ash.

The cleaned flue gas passes through a mist elimination section which may be an open louvre device, and is reheated before going to atmosphere via a stack. The design of the mist eliminator is important, and must allow for frequent cleaning of small segments in sequence by short bursts of fresh water to prevent blockage. Good design and operation allows for just the proper amount of make-up water to be used for this service.

Limestone is stored in a sheltered storage pile to protect it from rain and snow. The limestone is ground in ball mills, and then slurried in reclaim water from the sludge treatment section of the process. The feed rate of slurry to the absorber is controlled to be in accord with the incoming mass

rate of SO_2. Slurry density increases as reaction products are formed, so make-up water has to be added to maintain liquididty.

Net slurry of about 0.10 to 0.15 mass fraction solids, is purged to the thickener, whence it is increased to about 0.35 mass fraction of solids. This material is treated in the sludge stabilization system. It is filtered and combined with fly ash and calcined lime which by chemical action renders the entire mass of sludge unleachable. Hence it may be disposed of in the mine pit without fear of any of its constituents being leached out and finding their way into the ground water system.

Roughly speaking, for every tonne of sulphur absorbed, 3.3 tonnes of limestone and 0.15 tonnes of lime are required to be supplied and 9.5 tonnes of stabilized sludge are to be disposed of. This reveals the main disadvantage of this process. While the nuisances of the SO_2 and particulates are abated, there is the secondary effect of a significant disturbance of the environment, firstly in quarrying to supply the limestone and lime and secondly in disposing of the stabilized sludge.

In this type of wet flue gas absorber, most of the two to three micron diameter, or larger, contained solid particles will be captured, but the submicron particles will pass through undisturbed to the atmosphere. However this means that particulate emissions will be reduced from fifty to seventy per cent. In addition, as discussed in section 3.5.3, pages 3-15 and 3-16, the larger particles contain most of the heavy metals.

4.5 AQUEOUS AMMONIA FGD

The major attractions of this process are that it utilizes a project byproduct (aqueous ammonia) to capture the SO_2 in

the stack, and the resulting liquid solution of ammonium sulphate and ammonium bisulphite is potentially saleable as fertilizer. Like the limestone slurry process, it removes ninety per cent of the SO_2 and most of the particulates which escape the ESP. One possible disadvantage is that a prescrubbing flue gas wash produces a large volume of wash water which is assumed by Consultant to contain enough SO_2 and SO_3 to represent a disposal problem.

In the LC-Fining and hydrotreating processes some of the nitrogen contained in the bitumen feed is released as ammonia (NH_3) and in the normal course of processing ends up, along with some hydrogen sulphide (H_2S), in the sour water stream. The sour water is stripped of these substances and the estimated 100 to 150 daily tonnes ammonia are incinerated in the CO boiler. The information in the Dynawest Study is somewhat contradictory, but it would appear that one tonne of ammonia will capture about 3.0 tonnes of SO_2.

The calculations for this study confirm SCL's estimate of about 125 tonnes per day of sulphur, or 250 tonnes of SO_2 being emitted daily, and they further estimate a release of 147 tonnes per day of ammonnia. The ammonia estimate is not considered to be very accurate, and if it is off, the true rate would be lower. In addition, it is not well known how much of the released ammonia will be recovered in the sour water stripper, although almost all of the substance which reaches that unit will be reclaimed. Nonetheless the estimated amount of ammonia to capture the 250 tonnes of sulphur dioxide is about 85 tonnes, so even if the yield estimate is off, and the recovery not perfect, there still should be enough of the material.

The process, like the limestone slurry method, is a wet scrubbing operation. It is more sensitive, however, so the incoming flue gas is prewashed in a bernoulli scrubber, to remove most of the particulates. The wash water will have

small quantities of SO_2 and SO_3 in it, hence will be classified as "sour". A reflection of the import of this is that Dynawest have assigned a sum of six million dollars yearly for treatment of this stream. The flue gas must also be cooled below its abiabatic saturation temperature.

The absorber, because of the corrosive conditions, and the necessity of using bubble cap contactors, has trays made of an expensive alloy, Hastelloy. The flue gas enters at the bottom and flows upward and out whence it is reheated. The ammonium sulphite/bisulphite solution removes ninety per cent of the SO_2 present. The conditions at each of the four stages in the absorber must be carefully controlled to ensure good absorption and to minimize ammonia emissions. The product solution is about 0.17 mass fraction ammonium bisulphite and 0.07 mass fraction ammonium sulphate. It is potentially suitable for sale as fertilizer, which must be stored and shipped as a water solution.

There are some disadvantages of the process. Only one unit is in commercial operation, and it would be necessary to test the process with Syncrude's ammonia stream to evaluate the effect of trace constituents on both the process and the saleability of the product. Even though the operation is at low temperature (about 45°C) some ammonia evapourates and is emitted from the stack. This can form an objectionable blue haze, or its odour might be detected. The process has not been demonstrated at SO_2 concentrations above 0.0025 volume fraction, however it is believed that SCL's stack gases have an SO_2 concentration in the 0.0015 to 0.0020 volume fraction range.

The bernoulli scrubber, preceding the unit, and the trays in the absorber do impose a significant pressure drop penalty. The gain, though, is that virtually all the particulates are removed, probably well over ninety per cent.

4.6 SYNCRUDE INSTALLATION

Analysis of SCL's precise situation, in so far as retrofit of FGD is concerned is not within the scope of this study. However, examination of their plot plan indicates that there are two sites in the vicinity of the main stack where an FGD could be located, although if it were of the limestone slurry type, the reagent would have to be handled elsewhere. The flue gas leaving the ESP's is manifolded for flow to the main stack, and it appears that it could be intercepted fairly conveniently at that point and ducted to either site about 100 metres, or so, away. While there is room, the area is congested and construction would have to be very careful.

The FGD processes described above will require large, energy intensive fans to drive the flow of flue gas through their absorbers. It would probably be an induced draft fan(s) located downstream of the SO_2 absorber and reheat sections. Linking process plants in series can result in operating upsets being carried from one to the other, and in some cases being magnified. The effect of adding the FGD in series behind the Fluid Coker, the CO boiler and the ESP's is not fully known, but the fluidized bed in the burner of the Fluid Coker is a turbulent environment, and hence it can be concluded that safe design and operation of such a system is not a trivial engineering problem.

In both cases, it will be necessary to have at least two absorbers operating in parallel, and this also requires significant attention to design in order to equalize the flue gas flow to each one.

The ultimate conclusion is that FGD can be installed at SCL without undue difficulty or disruption, but it could be the cause of more frequent operating interruptions and possibly impact on synthetic crude oil production.

4.7 ECONOMICS

The basis of the Dynawest Study was a surface mining oil sands plant which was feeding an unstated volume of bitumen that contained precisely 1000 tonnes per stream day of sulphur. As it happens, it would be very close to 20,000 cubic metres per day.

They postulated an emission of 71 tonnes of sulphur daily from the Fluid Coker burner to the CO boiler and a Claus plant/tail gas clean-up combination which produces 911 tonnes per day of sulphur product while emitting "less than one" tonne per day of sulphur as SO_2. The FGD on the CO boiler recovered 64 tonnes per day leaving an emission rate of seven tonnes of sulphur as SO_2 daily, from that source, for a total of eight tonnes per day of sulphur, or sixteen tonnes per day of SO_2.

They further assume that the CO boiler flue gas to the FGD is 0.0060 mass fraction SO_2, or about 0.0025 volume fraction.

In Syncrude Canada Ltd's plant, for the expanded case, the sulphur in the bitumen totals 2300 tonnes per day, however the total from the CO boiler is 125 tonnes per day, a proportionately lower amount. This amounts to 1.75 times that in the Dynawest study.

It is estimated that the volume fraction of SO_2 in the flue gases leaving the ESP's is 0.002, compared to 0.0025 in the Dynawest work. So, in considering the relationship between the Dynawest capital costs and capacity, it must be recognized that SCL would have to process more flue gas per tonne of contained SO_2. The factor is about 1.25.

To estimate the FGD capital cost for Syncrude Canada Ltd, the base is 1.75 times the sulphur capture capacity of the Dynawest study. Using a 0.65 power factor, that leads to a

capital cost multiplier of 1.44. To allow for the additional volume of flue gas, an additional five per cent is applied, with the capital cost multiplier now 1.51.

The Dynawest Study also discusses retrofittng of FGD and the possible effect on capital cost. The three main elements that would appear to apply at SCL are moderate duct runs, a large induced draft fan(s) and tight plot availability. These factors are estimated to increase the capital cost by ten per cent, so the capital cost multiplier becomes 1.66.

Dynawest characterize the cost estimates as plus or minus thirty per cent. They are based on a Fort McMurray location, and a time frame of mid 1982. A somewhat arbitrary factor of 0.9 has been applied to reflect the drop in costs since then, which results in a final capital cost multiplier of 1.49.

In operating costs labour is unchanged, the other elements are multiplied by 1.75. In reviewing Dynawest's operating costs, it is not completely clear, but apparently there is no provision for maintenance, insurance or local taxes.

The estimated capital and operating costs for FGD installations at Syncrude Canada Ltd are listed overleaf in Table 4-1.

TABLE 4-1

FLUE GAS DESULPHURIZATION COSTS

PROCESS	CAPITAL COST	ANNUAL OPERATING COST				
		LABOUR	UTILS	MAT'LS	BYPRODUCT DISPOSAL	TOTAL
LIMESTONE SLURRY	126	1.8	4.7	5.4	4.2	16.1
AQUEOUS AMMONIA	97	1.4	19.0	1.0	6.0	27.4

costs are in million of Canadian dollars

PROCESS	CAPITAL COST	OP'NG COST	AMT'ZN	TOTAL ANN'L
LIMESTONE SLURRY	126	16.1	21.5	47.6
AQUEOUS AMMONIA	97	27.4	24.3	51.7

amortization is 25% of cap'l cost, or about a seven year payout

	SULPHUR CAPTURE	
	TONNES/YEAR	COST - $/TONNE
LIMESTONE	37,125	1282
AMMONIA	37,125	1391

FGD CAPITAL RELATED TO PROJECT COSTS

PROCESS	PER CENT of PROJECT	PER CENT of UPGRADING & UTILS
LIMESTONE SLURRY	3.2	7.5
AQUEOUS AMMONIA	2.5	5.7

total project 3.9 billion dollars
upgrading & utilities 1.69 billion dollars

FGD ANNUAL COST RELATED TO SCO PRODUCTION

ANNUALIZED COSTS in DOLLARS PER BARREL of SCO

PROCESS	BEFORE AMORTIZATION	AFTER AMORTIZATION
LIMESTONE SLURRY	0.54	0.18
AQUEOUS AMMONIA	0.58	0.31

sco prod'n 89 million barrels per year

The ammonia FGD operating costs have a large utilities component because of the high absorbent solution circulation rate and the pressure drop across the bernoulli scrubber and the absorber.

In calculating the cost of sulphur capture, an allowance of twenty-five per cent of the capital is allocated as an annual expense. The net result is a cost of around 1300 to 1400 dollars per tonne of sulphur captured. These costs are also related to project capital cost and production of synthetic crude oil.

Please note that no credit has been taken for byproducts. While Consultant is not familiar with fertilizer prices, it is assumed that shipping a water solution of 0.25 mass fraction would be expensive and the net revenue obtained would be minimal.

Because there are two absorbers in each of the processes discussed, there is the possibility of phasing construction of these installations. With the available information it is not possible to estimate the potential effect on costs, but this option could be attractive to the owner.

4.8 CLAUS TAIL GAS CLEAN-UP

The following section is rather hypothetical because Syncrude Canada Ltd are just in the process of completing construction of a Sulfreen unit which will meet all their requirements of Claus unit tail gas clean-up through the projected major expansion.

The unit is scheduled to be commissioned in late 1987 and will immediately reduce SO_2 emissions by about 38 tonnes per stream day, or fifteen per cent.

This evaluation will assess what the additional cost might

have been if SCL had selected a more efficient tail gas clean up process.

It may be helpful to describe briefly the Claus unit operation. In this process H_2S is converted to elemental sulphur. One third, precisely, of the incoming H_2S is burned to water and SO_2, then the conversion takes place over a catalyst in two or three (or even four) beds, or stages. The relevant chemical reaction is:

$$2H_2S + SO_2 \Rightarrow 3S + 2H_2O$$

The reaction does not go fully to completion which is why there is sulphur in the tail gas. A three stage unit will average 96.5 per cent conversion, with beginning of run at about 97.5 per cent and end of run drifting off to 95.5 per cent.

The Sulfreen process exploits the fact that a lower operating temperature will shift the reaction equilibrium towards greater completion, or conversion. The actual temperature is below the condensation point of sulphur, and the liquid sulphur accumulation on the catalyst eventually inhibits its function. This is overcome by having a series of beds which are switched in and out of service, and the accumulated liquid sulphur is removed to reactivate the catalyst.

The Claus/Sulfreen efficiency is thought to be slightly above nintey-nine per cent when the Sulfreen catalyst is new, drifting off to about 98.5 at the end of a cycle. Within reasonable limits, the overall result is not effected by the performance of the Claus units themselves. Carbonyl Sulphide (COS) and carbon disulphide (CS_2) are not reacted in Sulfreen. Thus, to maximize the overall efficiency, the Claus units must be very carefully operated to minimize formation of COS and CS_2. This process is very well demonstrated commercially.

The alternative process selected for comparison, Shell's SCOT, is also well demonstrated commercially. In this method, the effluent from the Claus unit is reacted with hydrogen over a fixed bed of cobalt molybdenum catalyst to convert all the sulphur back to H_2S. This compound is then absorbed in the conventional way by an amine, usually DIPA or MDEA. The recovered H_2S is recycled back to the Claus plant, which imposes a small additional load on the unit.

The overall efficiency of the Claus/SCOT combination is about 99.8 per cent. One of the reasons for this is that COS and CS_2 are converted and the sulphur recovered. In addition, there is little tendency for the efficiency to decline, as reduced catalyst activity is compensated for by raising the reaction temperature until the cycle is completed.

The Dynawest Study, Claus unit and associated tail gas clean-up are for a feed rate of 912 tonnes per stream day of sulphur. The SCL post-expansion Claus feed rate is 1990 tonnes per day of sulphur. Applying the 0.65 power factor to the 2.18 times feed rate gives a capital cost multiplier of 1.65 which becomes 1.48 when using the 0.9 adjustment. Operating cost is not detailed, as in the case of FGD, but that of Sulfreen is assumed proportional to sulphur throughput while a labour component is taken for SCOT. The estimated costs are found in Table 4-2 overleaf.

Please note that while SCL have used an overall efficiency through the Claus and Sulfreen of 98 per cent, in Table 4-2 the basis is the Claus plants at 96.5 per cent and the Sulfreen taking the overall operation to 99 per cent, as is cited in the literature.

TABLE 4-2

ECONOMICS of CLAUS UNIT TAIL GAS CLEAN-UP

PROCESS	SULPHUR EMISSIONS tonnes/day	CAPITAL COST M$	OPERATING COST M$	COST of SULPH CAPTURE $/tonne
NONE	66.0			
SULFREEN	22.6	17.8	1.96	448
SCOT	3.8	28.2	6.67	668

4.9 SUMMARY

It is important, here, to repeat that for both the FGD and Claus tail gas clean-up, the cost estimates were not of high quality. They should be considered notional, providing some insight into the subject but would require reworking to todays construction situation for a rigorous appraisal of the cost of reduction of emissions.

The conclusion concerning abatement of emissions, is that the most rewarding point to apply some effort would be to use FGD on the flue gas from the CO boilers, after the ESP's, just before it enters the main stack. A wet process would reduce sulphur dioxide emissions by about 225 tonnes per day and also greatly reduce particulate escape. The ESR process has the potential for somewhat greater sulphur reduction, with no secondary disposal requirements, but does not effect the particulates emission rate.

5.0 BEST PRACTICABLE TECHNOLOGY

The second objective of the study was to compare the upgrading technology selected by Syncrude Canada Ltd to at least one alternative which might have the possibility of being the Best Practicable Technology and showing some improvement in liquid yield and/or reduction in emissions.

For some time, high conversion black oil hydrocracking has been espoused as the best method for the upgrading of bitumen or heavy crude oils. Indeed, studies, such as the "AOSTRA/-Industry Upgrading Study" have determined that this method is economically superior to other approaches in an oil sands context. Up to this time, the problem is that these methods have not been demonstrated commercially at the high levels of conversion proposed. The heavy oil hydrocrackers now in operation run at conversion levels in the 55 to 60 per cent range, as will SCL's proposed LCF unit. The high conversion mode is usually considered to be ninety per cent, or higher.

Operators are extremely reluctant to make an unproven process the central element in a multi-billion dollar project, so it is not believed that there is any current plan to do so. In any case, it was felt that this approach had an opportunity to prove itself superior to SCL's configuration of low conversion hydrocracking followed by Fluid Coking.

The high conversion yields used in this study were, with the kind permission of AOSTRA, taken from the "AOSTRA/Industry Upgrading Study". The same computer model which was used to confirm SCL's liquid yields and sulphur and metals emissions was used for the evaluation.

The basis of comparison was to assume that CAP was in place and operating as in the Post-CAP yields and emissions in SCL's application. Then for "Expansion", the total bitumen

feed was made the same as the application, but all of the additional bitumen was devoted directly, or indirectly to a new high conversion hydrocracker. A consequence of this approach is that the throughput, and composition of feed to the coker remain identical.

As it happens, the yields from the AOSTRA study provide for the 525°C plus bitumen, or vacuum bottoms, to be fed to the hydrocracker. Thus there is a vacuum distillation column preceding the high conversion unit. The vacuum gas oil goes directly to the hydrotreaters. The liquid yield from the high conversion unit, comprising over 97 volume per cent of this low quality feed stock, also is fed to the hydrotreaters. The actual feed rate to the high conversion unit is 43,793 barrels per stream day of 525°C plus material, compared to 163,120 barrels per stream day to the expansion low conversion LCF. The high conversion residue is very heavy and resistant to processing, being closer to coke in properties than not. As it cannot be fed to the coker, it would likely be flaked and sent to the coke stockpile.

A schematic diagram, Figure 5.1, presents the hydrocarbon balance of the project on a barrels per calendar day basis. Also, Figure 5.2 is the sulphur balance and finally Figure 5.3 presents the heavy metals balance. In order that the reader may compare the difference in results more readily, Table 5.1 is very similar to Table 3.1. It has all the liquid flows from the diagrams tabulated side by side. Included are the data from Post-CAP, Expansion, High Conversion and the differences between Post-CAP and Expansion on the one hand and Post-CAP and High Conversion on the other.

As can be seen the results are disappointing, the high conversion mode yields 5,000 barrels per calendar day less synthetic crude oil (SCO) than SCL's Expansion program. The marginal yield is only 98.7 liquid volume per cent for high conversion, compared to 104.7 volume per cent. A clue to the

reason for this lies in the fact that the high conversion option yields about 180 tonnes per calendar day more of the useless residue, and that not as much hydrogen is consumed per barrel of bitumen fed. In sum, one could say, that in an effort to "add hydrogen" there is a synergism in being able to go the low conversion/Fluid Coker route that is not available to direct high conversion.

Table 5.2 is a tabulation of sulphur balances in the same manner as Table 3.2. Here again there is disappointment as SO_2 emissions increase by 26 tonnes per day in the high conversion case as compared to a 7.8 tonne per day reduction in the SCL Expansion configuration, a net loss of almost thirty-four tonnes per day. Here the reason is very easy to see. In the SCL Expansion case there is a reduction in sulphur in coker feed, resulting ultimately in a reduction in emissions from the coker burner which more than counter balance the increase in emissions from the Claus/Sulfreen units.

Because the coker feed remains the same in rate and composition, the emissions of particulates and heavy metals will also remain unchanged. In summary, then, the high conversion option results in less SCO, more residue, more SO_2 emissions and no change in particulate and heavy metal emissions.

It should be noted that the high conversion yields were provided in 1981 and probably could be improved upon today. It is expected, however that they could no more than match the SCL Expansion yields, and the SO_2 emissions increase would remain the same. High conversion hydrocracking is now much closer to commercial demonstration, but late in 1987, at the time of writing, it had still not occurred. So, as there is a perceived disadvantage, and little prospect of overcoming it, there would appear to be no reason to pursue this approach.

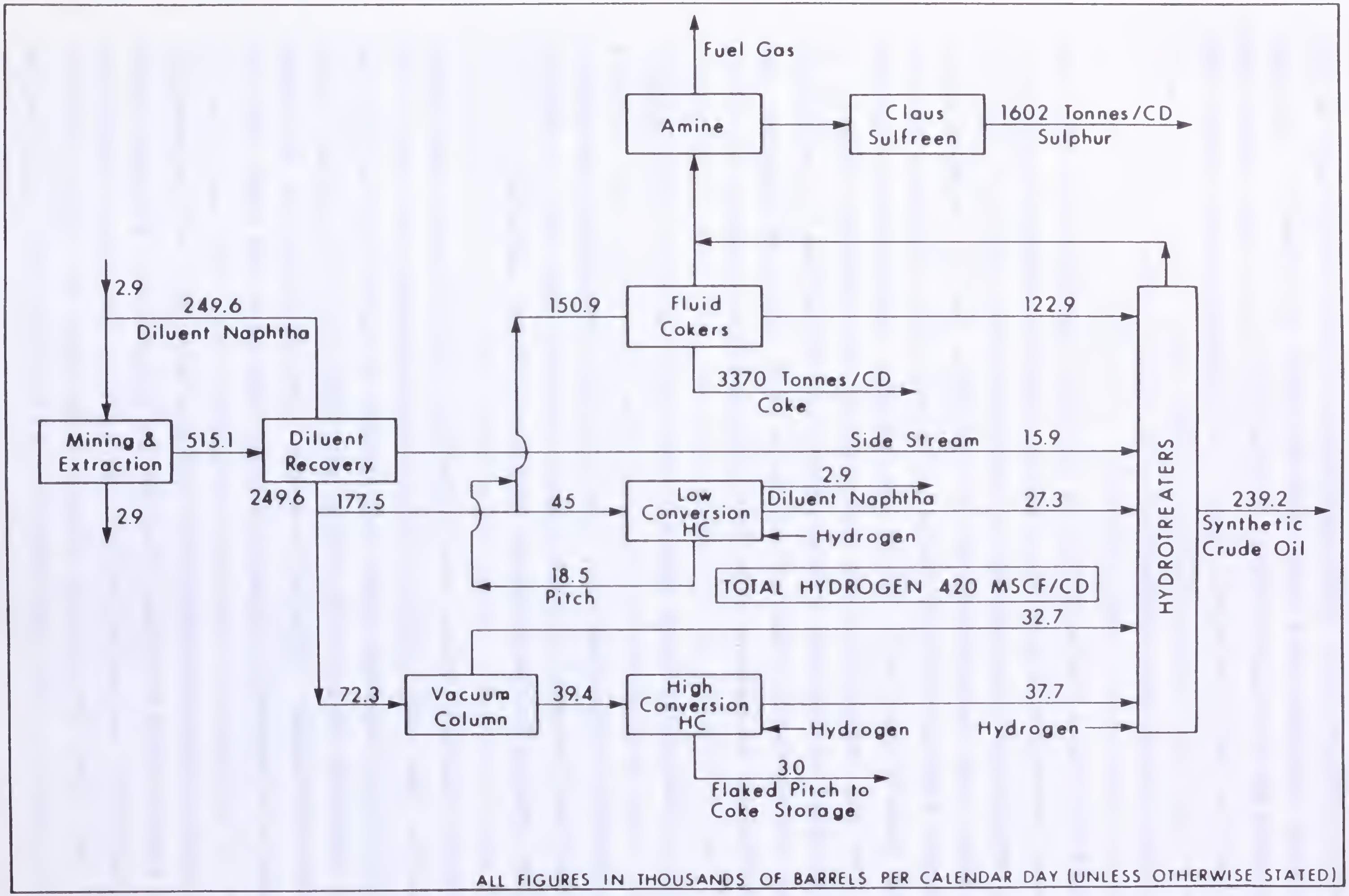


FIGURE 5.1 HIGH CONVERSION HYDROCRACKING HYDROCARBON BALANCE

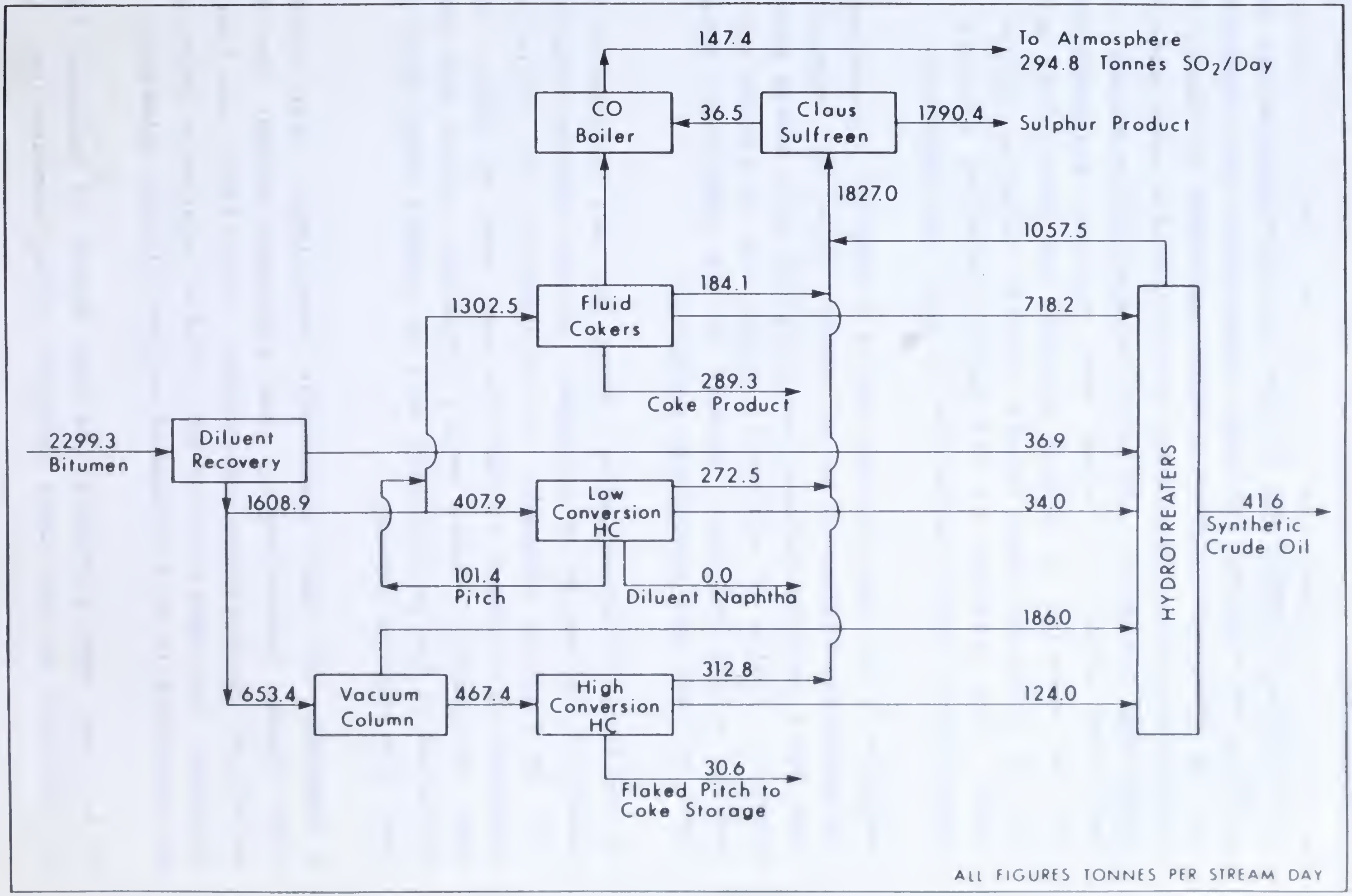


FIGURE 5.2 SULPHUR BALANCE

6.0 CONCLUSIONS

Consultant, on behalf of the Syncrude Expansion Review Group (SERG), has examined Syncrude Canada Ltd's (SCL) Application to the ERCB to undertake a major expansion of its Mildred Lake facilities. The project also entailed scrutinizing many associated documents, including internal SCL material. The particular areas of interest were yield of synthetic crude oil, and emission of sulphur dioxide, and particulate matter and its contained heavy metals, such as vanadium, nickel and lead. The licensor of the major upgrading process was consulted on factors pertaining to yield and emissions.

Analysis of the data through use of a computer simulation of the upgrading segment of an oil sands complex has established that SCL's proposed process configuration will indeed produce marginal yields of synthetic crude oil in excess of one hundred volume per cent, related to the additional bitumen feed, as they have accurately predicted.

In addition, notwithstanding a forty per cent increase in the amount of bitumen to be processed, sulphur dioxide emissions will be slightly reduced. It is expected that particulate emissions will remain at much the same level as today. However, the mass of heavy metals (vanadium, nickel and lead) contained in the particulates will be reduced about forty per cent from current levels.

A candidate for "Best Practicable Technology", high conversion bitumen hydrocracking, was evaluated against the SCL selection of upgrading technology. The result was disappointing, not equalling the SCL yield of synthetic crude oil and resulting in an increase of sulphur dioxide emissions.

It is clear that virtually the sole source of emission from the facility is the Fluid Coker/CO boiler combination, via

the main stack, hence the effect of applying flue gas desulphurization to this stream was examined. It would reduce SO_2 emissions by ninety per cent, to about twenty-five tonnes per day. In addition it would reduce particulate emissions very substantially, fortuitously eliminating most of the heavy metal bearing larger diameter particles. There is no question but that installation of such a process would dramatically reduce the discharge of pollutants from the SCL Mildred Lake Facility.

APPENDIX B

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

EXPANSION OF THE SYNCRUDE MILDRED LAKE OIL SANDS PLANT

Decision D 88-6
Application 870593

1 INTRODUCTION

1.1 Application

Syncrude Canada Ltd. (Syncrude) applied pursuant to section 14 of the Oil Sands Conservation Act to amend its existing Approval No. 4973 to increase yearly synthetic crude oil and naphtha production from a current level of 8.375 million cubic metres (10^6 m^3) to 10 x 10^6 m^3 of synthetic crude oil by modifications to currently approved facilities, and then to 15 x 10^6 m^3 of synthetic crude oil from an expanded mine and plant facilities including a new extraction plant. The expansion from 10 x 10^6 m^3 to 15 x 10^6 m^3 is currently called the Syncrude Expansion Project.

2 BACKGROUND TO THE APPLICATION

The Syncrude project comprises an open-pit mine using draglines, bucketwheel reclaimers, and conveyors to transport the bituminous sands to an extraction plant where a hot water process is used to separate bitumen from the sand. Tailings from the extraction plant containing sand, clay, hydrocarbon sludge, and water are currently directed in slurry form to a tailings pond. As mined-out areas become available they will be used for tailings storage. The bitumen is upgraded to synthetic crude oil using fluid coking, hydrocracking, and hydrotreating processes. Solid by-products include sulphur, which is marketed, and coke, which is stored.

3 INTERVENTION AND HEARING

Oleophilic Sieve Development of Canada Ltd. (OSDC) filed an intervention to Application No. 870593 on 12 August 1987 raising a number of concerns with the Syncrude Expansion Project, particularly with the extraction process selection. Syncrude proposed installing a Warm Slurry Process (WSP) to provide the required additional bitumen extraction capacity. OSDC identified three areas in which an alternative extraction process, using an oleophilic sieve which it has developed, would be beneficial to the proposed expansion:

(i) mined oil sands processing claimed to achieve higher bitumen recovery, require less energy and fresh water, and help in cleaning up the environment,

(ii) mined oil sands processing with tailings sludge recycle to recover bitumen from the sludge, and

(iii) mined oil sands processing with tailings runoff recycle to recover the bitumen present in runoff.

OSDC asked the Energy Resources Conservation Board (Board) to recognize the long-range implications of new and better bitumen extraction technology to reduce pollution and minimize water and energy resources waste in oil sands development. Specifically, OSDC requested:

- an opportunity to build and operate a field demonstration sludge recycle plant leading to the commercial recovery of bitumen from the Syncrude tailings pond, and

- an opportunity to work with Syncrude so that in time it can prove or disprove the merits of its claims for processing mined oil sands with water, with tailings runoff, and with sludge, using its technology.

Over a period of months as indicated in Table 1, after the intervention was filed the claims of OSDC and the question of testing the process at the Syncrude site were jointly reviewed among Mr. Jan Kruyer (OSDC), Board staff, and Syncrude staff.

Despite the exchange of information, the issues were not fully resolved. As a result, the Board held a hearing on 24 March 1988 with N. A. Strom, P.Eng., sitting as a single-member panel to consider submissions regarding the intervention of OSDC in the matter of Application No. 870593 by Syncrude Canada Ltd. to expand its Mildred Lake facilities.

The participants in the hearing are listed in Table 2.

4 ISSUES

The panel considers the main issues to be:

- Need for Technology Development
- Bitumen Recovery
- Water Use
- Energy Efficiency
- Tailings/Sludge Accumulation
- Applicability of OSDC Technology to Address the Needs
- Access for Field Demonstration Tests at Oil Sands Mining Sites

5 NEED FOR TECHNOLOGY DEVELOPMENT

The bitumen extraction technology employed by Syncrude is a development of the Clark hot water process. When initially applied commercially, at the Great Canadian Oil Sands plant (GCOS), the limitations of this process with regard to bitumen recovery, fresh water use, energy efficiency, and sludge production became evident. These limitations were singled out as points of concern by the Board in three decision reports on mineable oil sands project applications in 1974 and 1975 and again cited as concerns in the 1979 Alsands Decision Report.

Recognizing the need for extraction technology improvement and the long lead time between basic research, development, and commercial implementation, the Board in 1982 commissioned a study of alternative bitumen extraction technology. This study, though it did not address tailings management, concluded that alternative processes such as the Taciuk, Syncrude Two-Stage Flotation, and OSDC processes had potential for increased bitumen recovery, less fresh water use, and higher energy efficiency. Of the above processes, the Taciuk process was considered to have the best long-term potential. As highlighted in the Board's Informational Letter IL 84-6, attached as Appendix A, it was evident that the tailings management requirements for all the alternative processes were largely unproven, and that further study, including research and development in the area of extraction technology, particularly with regard to reducing tailings sludge accumulation, was necessary.

The tailings sludge accumulation concern results from the fact that tailings from aqueous extraction processes do not settle readily due to the presence of dispersed bitumen, clays, and fine solids. The disposal of tailings at existing commercial operations has resulted in an overall bulking factor in excess of 1.4; ie. tailings volumes are more than 40 per cent larger than the volumes of the in-place mined oil sands. This presents major material handling problems, necessitates very large tailings ponds, and is an environmental concern.

The sludge accumulation rate has been a major concern since the late 1960s when GCOS (Suncor) first encountered slow settling oil sands tailings. Since then, Suncor and Syncrude, along with Alberta Research Council (ARC) and other public and privately funded research centres, have devoted research effort toward understanding sludge properties and trying to find a method to reduce or eliminate the sludge. However this effort has not yet been successful in significantly reducing sludge volumes.

5.1 Syncrude's Views

Syncrude recognized the need for work on oil sands tailings to attempt to find a more effective reclamation strategy for treatment and reclamation of the sludge.

5.2 OSDC's Views

OSDC stated that there is a need to develop technology which deals with toxic sludge produced by existing mined oil sands operations and that it has developed such technology which it believes addresses the Board's objectives as set out in Informational Letter IL 84-6 (attached).

5.3 Board's Views

The panel sees no reason to alter views previously expressed by the Board and reaffirms the objectives set out in IL 84-6.

6 BITUMEN RECOVERY

6.1 Syncrude's Views

Syncrude expected 94.4 per cent bitumen recovery based on total oil sands feed or 96.3 per cent excluding oversize materials rejected after the oil sands conditioning step of its extraction process. Bitumen loss to oversize reject of approximately 2 per cent is assumed by Syncrude to be the same for both WSP and OSDC processes. Syncrude noted that WSP pilot plant testing has met or exceeded hot water process recoveries and that its commercial plant tests confirm the pilot results. At present, actual plant performance is 93.1 per cent bitumen recovery based on total oil sands feed or 95.8 per cent excluding oversize materials rejected after the conditioning step. The net result is that 4.2 per cent (100 - 95.8) of the bitumen remains in the fluid waste tailings.

6.2 OSDC's Views

OSDC claimed that its process would achieve 96.3 per cent bitumen recovery based on total oil sands feed or 98.3 per cent excluding oversize materials rejected after the conditioning step. Additionally, OSDC claimed that in an alternative application of its process in which tailings from the expansion extraction plant would be recycled, bitumen supply for upgrading could be increased by approximately 950 cubic metres per day (m^3/d). It acknowledged that its claims were based on limited small-scale testing and lacked demonstration at precommercial levels.

6.3 Board's Views

The panel recognizes that considerable progress has been made by Syncrude to test and install improvements to the hot water process. However, the panel continues to hold the view that further improvements in extraction technology are desirable to effect sound resource conservation. Processes downstream of the existing hot water extraction area may well be the means by which overall extraction efficiencies exceeding 95 per cent (based on total oil sands feed) could be achieved. At the present time, there are substantial bitumen losses to tailings and if there is a practical method to significantly reduce or eliminate those losses it should be thoroughly investigated and tested without delay.

7 WATER USE

7.1 Syncrude's Views

Syncrude proposed to increase fresh water intake from 32.5×10^6 cubic metres per year (m^3/yr) to 40.5×10^6 m^3/yr primarily to provide for cooling in the expanded upgrading area after which it is sent to the tailings pond. In turn, the expanded extraction facility would operate totally on recycle water from the increased tailings pond water inventory.

7.2 OSDC's Views

OSDC claimed that recycle of tailings runoff or sludge as proposed using its technology would result in lower fresh water requirements because its process would produce a denser tailings, and therefore would retain less water.

7.3 Board's Views

The panel notes that Syncrude's make-up water requirements have been progressively reduced from approximately 7 m^3/m^3 of synthetic crude oil (SCO) initially to 3.4 m^3/m^3 of SCO currently and are projected to reach 2.9 m^3/m^3 SCO for the expanded project. Also, the panel notes that the major need for water results from the use of aqueous extraction processes in the conditioning step common to both the Syncrude WSP and OSDC processes. Ultimately, even under a complete water recycle process, incremental water make-up would be needed to fill sand voids and make up for bitumen that could be recovered from the tailings impoundment. While the OSDC process theoretically would lead to less water to fill the tailings sand voids, the concept is far from being demonstrated and at this point could not be seen as assuring overall reduced water requirements. The panel therefore is doubtful that the OSDC process would result in a significant reduction in water make-up requirements.

8 ENERGY EFFICIENCY

8.1 Syncrude's Views

Syncrude stated that the WSP offers several advantages over the existing hot water process in terms of reduced energy input. These include lower operating temperatures, the fact that no steam is required for the conditioning step, and that waste heat energy from upgrading process units is available to provide required low-grade energy. With reference to the OSDC proposed recycle options, Syncrude stated that the high silt and clay content of the runoff water would prevent its use for waste heat recovery in upgrading. Also, due to low temperature of runoff, additional heat would be required for oil sands lump size reduction in conditioning step of either OSDC or Syncrude aqueous extraction processes.

8.2 OSDC's Views

OSDC has looked at current heat balances and on the basis of utilizing waste heat in the tailings has concluded that its process would not require additional heat energy. It believes that, using the OSDC process, there is enough heat contained in Syncrude tailings to operate a mined oil sands extraction plant with a capacity equal to the proposed Syncrude expansion.

8.3 Board's Views

Evidently, the warm slurry process offers significant improvement over the previous hot water process in terms of energy efficiency. Also, low grade waste heat available from either the upgrading area or the tailings area could be utilized for pre-heating in the extraction area. If waste heat from the tailings area were accessed as proposed by OSDC, it appears that the more readily accessible low grade heat from the upgrading area would not be utilized. Therefore the potential theoretical net energy gain put forward by the OSDC process is speculative unless some other use can be found for the low-grade waste heat.

9 TAILINGS/SLUDGE ACCUMULATION

9.1 Syncrude's Views

The extraction process proposed by Syncrude would produce tailings with similar settling characteristics and sludge accumulation rates to those from the existing plant. Syncrude advised that sludge accumulation to date is 2.3 m^3/m^3 of synthetic crude oil. Syncrude experience is that sludge has been observed to increase in density from its initial value of 15 per cent solids to a density after 10 years of 35 per cent solids. Further densification is very slow and, based on experimental work, Syncrude expects that ultimate sludge density will not exceed 42 per cent solids regardless of whether sodium hydroxide was or was not used in the process.

Syncrude acknowledged that sludge accumulation is a continuing concern and in that regard Syncrude advised that it has a joint program with ARC, Canada Centre for Mineral and Energy Technology (CANMET), and Environment Canada to study the fundamental physico-chemical properties of tailings sludge. The program commenced 2 years ago and has 8 or 9 months left to completion. Syncrude advised that the information produced in this program will be in the public domain and it expects that a report will be released after the program is complete.

In response to OSDC's claim that the use of sodium hydroxide results in sludge becoming toxic, Syncrude stated that the toxicity of sludge is associated predominantly with the naphthenic acids originating from the residual bitumen fraction accumulated in the sludge and that these acids are released somewhat more rapidly with sodium hydroxide. Given time, however, Syncrude expects them to reach a similar concentration without sodium hydroxide.

Syncrude believes that bitumen recovery from sludge is associated more with the existing operation and tailings pond reclamation than it is with expansion. It considers the sludge as a poor quality ore and concludes that it does not make economic sense to consider recovering bitumen from sludge unless it is being moved. Syncrude anticipates transfer of sludge to the mined-out pit would start in 1997 or earlier. Syncrude believes that recovery of bitumen from sludge should be evaluated in conjunction with this sludge transfer operation.

Syncrude indicated that it has discussions under way with Alberta Oil Sands Technology Research Authority (AOSTRA) and Suncor to develop a proposal for a shared-cost program on bitumen recovery from sludge. The focus of such a program would be directed towards recovery of bitumen from tailings pond sludge as part of the generation of technology for future use in reclamation. It would not be exclusively directed at evaluating the OSDC process but all options would be reviewed using a rational process of selection, and thence to field piloting on that option which was seen to be best. Syncrude maintained that any field demonstration of a process should be preceded by adequate bench scale or off-site pilot work and engineering analyses to establish maximum possibility for success of a commercial application.

9.2 OSDC's Views

OSDC referred to two aspects of its process which could provide potential advantages over current extraction technology. Firstly, it believes that since its process would not require steam and sodium hydroxide, a colloidal sludge would not be generated and the OSDC tailings material would undergo rapid densification. Therefore it would expect the sludge accumulation problem would be largely eliminated. In turn, tailings storage requirements would be greatly reduced and this would negate existing concerns about tailings dike integrity, seepage of toxic tailings, and site reclamation. Secondly, it the OSDC process were utilized to reprocess sludge from the Syncrude pond, approximately 1600 m^3/d of bitumen could be recovered over 27 years.

OSDC further claimed that it has demonstrated, through pilot plant and field tests, that its process is well suited for bitumen recovery from tailings pond sludge. It advised that Suncor is encouraged with the results of field testing it participated in with OSDC and AOSTRA and wishes to see one more field test. OSDC believes the next field program should be on the Syncrude site.

In response to a question on studies of OSDC tailings settling properties OSDC stated that, although it has not conducted experimental work, its review of the literature and particularly ARC work indicates that when sodium hydroxide is not used in the extraction process, sludge settles to a denser state.

OSDC argued that the sludge recycle to its extraction process would result in a denser tailings stream and entrap more sludge in sand voids. In response, Syncrude stated that incorporation of sludge in tailings sand is an objective it also has for reducing sludge volume and noted that the limit for incorporation would be dictated by the strength of the resulting sand/sludge material. Syncrude advised that in its current operation about half of the fines are already captured and incorporated in the tailings pond beach.

9.3 Board's Views

The panel is of the view that both the question of the source of toxicity and the continuation of sludge tailings management issues are

reasons for renewed and concerted efforts to solve those problems. While the panel agrees with Syncrude that it is preferable to have reliable laboratory-scale information on all potential methods which might deal with the sludge problem before selecting methods for field demonstration, it is of the opinion that the rate of progress in this area has not been altogether satisfactory. Therefore some means must be found to accelerate demonstration and proving up of one or more effective methods.

The panel proposes that the following or similar targets be established respecting the sludge problem and that a joint industry/government program be established with the following objectives:

1. Determine the source and implications of sludge toxicity, and facilitate accelerated development of technology to reduce or eliminate sludge toxicity to environmentally acceptable levels.

2. Facilitate rapid development of sludge densification technology aimed at reducing the overall tailings bulking factor to a level below 1.2.

3. As offshoots of the preceding, facilitate further research on tailings reprocessing to achieve economic recovery of residual bitumen left in the tailings streams and ensure an overall recovery of 95 per cent or more of the mined oil sands bitumen feed.

10 APPLICABILITY OF OSDC TECHNOLOGY TO ADDRESS THE NEEDS

10.1 Syncrude's Views

Syncrude pointed out that the OSDC process has no advantage in terms of higher bitumen recovery potential, improved characteristics for disposal and reclamation, reduced energy input or simpler lower cost process equipment which is easier to maintain and operate. Also the OSDC process appears to have significant disadvantages in the area of mechanical complexity, operability, and maintainability.

Syncrude contended that systematic screening is needed to ensure selection of a process with a high possibility of success for field demonstration and commercialization. Field demonstration of the OSDC process without screening would be inappropriate. Also, the OSDC process for bitumen extraction from mined oil sands is not at the stage of development which would allow engineering of a commercial-scale plant.

10.2 OSDC's Views

OSDC claimed that it has demonstrated, through pilot plant and field tests, that its process is well suited for bitumen recovery from tailings pond sludge. OSDC stated that it is prepared to proceed immediately with a field demonstration, provided that required funds of $1 million and a suitable test site were available.

OSDC rejected Syncrude arguments on process complexity and stated that its process is in some respects less complex than Syncrude's.

10.3 Board's Views

The panel understands that the bench scale tests and the limited field tests conducted by OSDC at the Suncor site are inadequate to confirm with reasonable certainty the claims made by OSDC regarding level of recovery of bitumen from sludge, reductions in sludge bulking, and the avoidance of toxicity. In those respects the panel regards the OSDC process as one of potential that may or may not prove successful.

11 ACCESS FOR FIELD DEMONSTRATION TESTS AT OIL SANDS MINING SITES

11.1 Syncrude's Views

Syncrude stated that it is appropriate for the Board to encourage work on improved resource use objectives; however, it did not believe that the ERCB application process was the appropriate forum to debate or select companies' offerings of processes or equipment.

Syncrude requested that no specific conditions be attached to the Board's approval with respect to the use or support of further development of the OSDC process.

11.2 OSDC's View

OSDC requested the Board to provide it the opportunity to build and operate a field demonstration sludge reprocessing plant on Syncrude's site and to work with Syncrude so that in time OSDC could prove or disprove its claims of superior technology for processing mined oil sands with water, with tailings runoff, and with sludge.

11.3 Board's Views

Considering the fact that commercial operations in the mineable oil sands are and can be expected to be very large scale and few in number, the panel believes that demonstration of desired and potentially beneficial technology at existing operational projects is a matter of public priority, irrespective of the operatorship of the project or the ownership of the new technology to be demonstrated. By arranging for existing project operators to make available site space, utilities, and oil sands materials to be processed, promising new technologies could be demonstrated without undue delays. Indeed, Syncrude pointed out that it does not place a priority on in-house technology but rather searches for early application of any promising technology. The panel also understands this to mean that Syncrude would welcome early demonstration of any such technologies at its project site.

The panel believes that it may not be appropriate to incorporate requirements in the Syncrude Expansion approval respecting arrangements

for demonstration of oil sands experimental technology. Also the panel recognizes that the Syncrude Expansion program per se should not be unnecessarily impeded pending completion of arrangements that would allow third-party access to the Syncrude site. Nevertheless the panel continues to believe that accelerated field demonstration of promising new oil sands mining-area technology can only be achieved by utilization of existing oil sands operational sites, including that of Syncrude. As well, the panel suggests that the most appropriate vehicle for directing third-party demonstration programs at operating oil sands sites would be through the joint industry/government program proposed in Section 9.3 of this report. The panel further suggests that this program be headed by a small advisory board with representatives of operating oil sands mines, (currently only Syncrude and Suncor), and research and government agencies.

12 RECOMMENDATION

The panel recommends that the ERCB initiate discussions with industry and government with the objectives of:

1. Establishing a suitably constituted advisory board to give general direction for accelerated field demonstration of experimental oil sands technology at existing oil sands mining sites.

2. Confirming guidelines for and accelerated resolution of oil sands mining tailings sludge issues.

The panel further recommends that the OSDC request for access to the Syncrude site not be made a condition of the Syncrude expansion approval, but instead any such requests for access by third parties for field demonstration testing at operating oil sands mine sites, including those of Syncrude or Suncor, be facilitated by the joint industry/research/government advisory board.

DATED at Calgary, Alberta on 30 May 1988.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

TABLE 1 CHRONOLOGY OF SUBMISSIONS AND MEETINGS

Meetings:	- ERCB/Kruyer; 25 August 1987
	- ERCB/Kruyer/Syncrude; 3 September 1987
	- ERCB/Kruyer; 7 January 1988
	- ERCB/Syncrude; 12 January 1988
	- ERCB/Syncrude; 27 January 1988
Submissions:	- Kruyer to ERCB; 4 September 1987, 22 September 1987, 1 October 1987, 10 December 1987, 12 January 1988, and 19 January 1988.
	- Syncrude to ERCB; 10 November 1987

TABLE 2 THOSE WHO APPEARED AT THE HEARING

Syncrude Canada Ltd. (Syncrude)

A. W. Hyndman, P.Eng.
J. E. Clark, P.Eng.

Oleophilic Sieve Development of Canada Ltd. (OSDC)

Jan Kruyer, P.Eng.
Johanna Kruyer

Department of Environment

Andrew Cummins

Energy Resources Conservation Board staff

R. G. Evans, P.Eng.
Dr. R. N. Houlihan, P.Eng.
M. Dmytriw, R.E.T.

APPENDIX C

THE PROVINCE OF ALBERTA

OIL SANDS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Her Majesty the Queen in right of Alberta as represented by the Minister of Energy, Alberta Energy Company Ltd., Canadian Occidental Petroleum Ltd., Esso Resources Canada Limited, Gulf Canada Resources Limited, HBOG - Oil Sands Limited Partnership, PanCanadian Petroleum Limited and Petro-Canada Inc. for the recovery of oil sands or production of oil sands products from the Athabasca Wabiskaw-McMurray Oil Sands Deposit in the Mildred Lake area

APPROVAL NO. 5641

WHEREAS the Energy Resources Conservation Board, by Approval No. 1920, approved a scheme of Atlantic Richfield Canada Ltd., Canada-Cities Services Ltd., Gulf Oil Canada Limited and Imperial Oil Limited for the recovery of oil sands or production of oil sands products; and

WHEREAS Syncrude Canada Ltd. applied for approval of a revision to the scheme and Approval No. 2959 superseded Approval No. 1920; and

WHEREAS Syncrude Canada Ltd. applied for approval of a revision to the scheme and Approval No. 4973 superseded Approval No. 2959; and

WHEREAS the Board is prepared to grant an application by Syncrude Canada Ltd. for approval of a revision to the scheme and it is desirable that a new approval be issued to replace Approval No. 4973, subject to the conditions herein contained; and

WHEREAS the Lieutenant Governor in Council, by Order in Council numbered O.C. ____/___ and dated ________________, has authorized the granting of the approval subject to certain conditions set out in the Order in Council hereto attached; and

WHEREAS the Minister of Environment has given his approval, hereto attached, insofar as the application affects matters of the environment, and the Associate Minister of Forestry, Lands and Wildlife has given his approval, hereto attached, insofar as the application affects land and resources that are the property of the Crown in right of Alberta.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Oil Sands Conservation Act, being chapter O-5.5 of the Statutes of Alberta, 1983, hereby orders as follows:

1. (1) The scheme of Her Majesty the Queen in right of Alberta as represented by the Minister of Energy, Alberta Energy Company Ltd., Canadian Occidental Petroleum Ltd., Esso Resources Canada Limited, Gulf Canada Resources Limited, HBOG - Oil Sands Limited Partnership, PanCanadian Petroleum Limited and Petro-Canada Inc., developed and operated on their behalf by Syncrude Canada Ltd. (which are hereinafter collectively called "Syncrude") for the recovery of oil sands or production of oil sands products, taken from the area shown outlined on the attachment hereto, marked Appendix A to this approval, as such scheme is described in the following applications and associated supporting material:

(a) Application No. 957 dated 9 May 1962 as amended to 3 May 1968 and to 24 March 1969 and to 7 August 1971,

(b) Applications No. 6888 and 6889 dated 5 March 1973,

(c) Application No. 9160 dated 19 February 1976,

(d) Application No. 9775 dated 8 November 1976,

(e) Application No. 790543 dated 17 July 1979,

(f) Application No. 820394 dated 21 April 1982,

(g) Application No. 821217 dated 7 December 1982,

(h) Application No. 840232 dated 23 December 1983,

(i) Application No. 840142 dated 9 February 1984,

(j) Application No. 841228 dated 28 November 1984,

(k) Application No. 841319 dated 17 December 1984,

(l) Application No. 851024 dated 23 September 1985, and

(m) Application No. 870593 dated 27 April 1987,

is approved, subject to the Oil Sands Conservation Regulations and the terms and conditions herein contained.

(2) Subclause (1) does not preclude alterations in design or equipment compatible with the outline of the scheme and made for the better operation of the scheme.

2. (1) The project area shown on Appendix A, hereto attached, is approved subject to Syncrude submitting for the Board's approval mine and discard disposal plans prior to 31 December 1994, or such other date as may be specified by the Board.

(2) Syncrude will also provide prior to 31 December 1994 what the intended use is for the area West of the McKay River and for the area North of Township 93 as part of the plan referred to in subclause (1).

(3) Should the Board deem that an area within the project area submitted under subclause (1) will not be needed prior to 31 December 2018 it may alter the project area accordingly.

3. (1) This approval applies to the production in each calendar year of

(a) 10 000 000 cubic metres of synthetic crude oil from the date of this approval until completion of construction of the new facilities described in Application No. 870593,

(b) 15 000 000 cubic metres of synthetic crude oil on completion of construction of the new facilities described in Application No. 870593, and

(c) marketable hydrocarbons recovered from the process gas.

(2) Syncrude shall commence construction of the facilities applied for in Application No. 870593 on or before 31 December 1992 and shall proceed with the expeditious completion of all facilities unless, upon application by Syncrude, a later date or revised construction plan is approved by the Board.

(3) The approval for those facilities applied for in Application No. 870593 for which construction has not started shall lapse if the conditions of subclause (2) are not met.

4. Syncrude shall study and report to the Board, by 31 December 1990, or such later date as the Board may require, on its research and development work on

(a) maximizing the recovery of bitumen and other oil sands products from accumulated tailings,

(b) minimizing the accumulation of tailings water, and

(c) minimizing the ultimate volume of tailings material requiring impoundment.

5. (1) Syncrude shall design and construct the new facilities so as to not make more difficult the possible future installation of facilities to treat stack gas for the removal of sulphur dioxide, particulates and heavy metals.

(2) Syncrude shall study and report to the Board, by 30 June 1991, or such later date as the Board may stipulate, as to the technical and economic suitability of installing facilities to treat stack gas for the removal of sulphur dioxide, particulates and heavy metals.

6. Syncrude shall study and report to the Board, by 30 June 1991, or such later date as the Board may stipulate, as to the technical and economic feasibility of the recovery of marketable hydrocarbons from the process gas.

7. Unless the Board otherwise approves, Syncrude shall carry out its operations to the satisfaction of the Board and in a manner that, under normal operating conditions,

(a) results in the recovery of not less than 92 per cent of the crude bitumen contained in the oil sands processed by the extraction plant,

(b) results in the recovery in the form of elemental sulphur of,

(i) from the date of this approval, not less than 95 per cent of the sulphur contained in the gas delivered to the sulphur recovery plant during each three-month period beginning 1 January, 1 April, 1 July or 1 October, and

(ii) from 1 July 1989, or such other date as the Board may stipulate, not less than 98 per cent of the sulphur contained in the gas delivered to the sulphur recovery plant during each three-month period beginning 1 January, 1 April, 1 July or 1 October.

8. (1) Syncrude shall measure, or otherwise determine, the quantities and other pertinent characteristics of oil sands mined, oil sands processed, crude bitumen recovered, and distillate, synthetic crude oil, coke and sulphur produced, using sound engineering techniques.

(2) The measurements or other information referred to in subclause (1) shall be made with sufficient frequency and accuracy as to allow calculations, to the satisfaction of the Board, of mass balances, energy balances and recovery efficiencies for bitumen extraction, bitumen upgrading, gas and sulphur recovery and water and utility systems.

9. (1) Syncrude shall remove all materials from the discard site, shown as NT1 on Appendix A, prior to 31 December 2003 or such other date as the Board may approve.

(2) The oil sands in the area shown as NT1 on Appendix A shall be mined.

10. (1) Syncrude shall submit to the Board by 30 June 1990 an estimate of crude bitumen reserves for marine ore and crude bitumen recovery rates from marine ore.

(2) Marine ore is defined as a mixture of sand, silt and clay deposited in a marine environment containing a minimum of 6 per cent bitumen saturation by weight.

11. (1) The areas shown outlined on Appendix A, and labelled as S-4, S-5, W-1 and W-2 (east), are approved for the permanent storage of overburden materials removed from any mine pit developed in the area shown outlined on the above noted attachment.

(2) Notwithstanding subclause (4), the area shown outlined on Appendix A, and labelled as Southwest Sand Disposal,

is approved for the permanent storage of tailings sand subject to Syncrude obtaining all necessary approvals from Alberta Department of Energy with respect to access to the minerals.

(3) Syncrude shall submit to the Board for its approval, not less than six months prior to commencement of construction, the following information for the S-5 discard site referred to in subclause (1):

(a) an isopach map of the muskeg thickness,

(b) an isopach map of the Clearwater Formation underlying the discard site,

(c) a drainage plan if the muskeg is planned to be drained,

(d) a construction plan and rate of construction for each overburden lift placed on the site,

(e) a revised stability analysis for critical sections of the proposed site based on additional information with respect to muskeg and Clearwater Formation thickness, and

(f) any other informtion the Board may require.

(4) Syncrude shall submit to the Board for its approval, not less than six months prior to commencement of construction, or such other time as specified by the Board, the following information for the W-1, W-2 (east) discard sites referred to in subclause (1) and the Southwest Sand Disposal discard site referred to in subclause (2):

(a) an isopach map of the muskeg thickness,

(b) an isopach map of the Clearwater Formation underlying the discard sites,

(c) design and construction plans and rate of construction for each site,

(d) details on the stability analysis for the proposed construction plans,

(e) an evaluation of the volumes of crude bitumen in place under the proposed discard site, and

(f) any other information the Board may require.

12. (1) Syncrude shall submit to the Board for its approval, one year or such other time as specified by the Board prior to commencing field preparation of any permanent or temporary discard site not referred to in subclauses 11(3) and 11(4), an application for the construction of the discard site.

(2) The application required by subclause (1) shall include

(a) a statement as to the need for the discard site,

(b) a description of Syncrude's evaluation of any alternative discard sites and the reasons for selecting the proposed site over the alternatives studied,

(c) drawings to show the design and location of the proposed site,

(d) geotechnical information used in the design,

(e) an evaluation of the volumes of crude bitumen in place under the proposed discard site,

(f) an evaluation of the mineable oil sands reserves under the proposed discard site supported by current unit cost information, and

(g) any other information the Board may require.

(3) For any discard site referred to in subclause (1), and at the time of the application for said discard site, Syncrude shall submit the following information for review and transmittal to the Department of the Environment:

(a) a preliminary assessment of the biophysical impacts of the proposed site and any alternative site considered, and

(b) a preliminary development and reclamation plan showing key aspects of site preparation and construction.

13. (1) Unrecovered equivalent sulphur from the plant incinerator and boiler stack shall not exceed 146 tonnes per day.

(2) Unrecovered equivalent sulphur from the plant incinerator, boiler stack, and from all flare stacks shall not exceed,

(a) from the date of this approval, 140 tonnes per day equivalent sulphur calculated on a rolling average for that day and the previous 89 days, and

(b) from 1 July 1989, or such other date as the Board may stipulate, 132.5 tonnes per day equivalent sulphur calculated on a rolling average basis for that day and the previous 89 days.

(3) Notwithstanding subclause (2), Syncrude shall report to the Board by 31 December 1989 on plant sulphur recovery performance following operation of the Sulfreen plant after which time the Board may increase the required sulphur recovery to an appropriate level.

14. (1) Syncrude shall operate the plant so that flaring or waste of liquid or gaseous hydrocarbons is minimized.

(2) For sustained flaring conditions, flares shall be operational under conditions of controlled combustion.

15. (1) Six months after commencement of the operation of the facilities described in Application No. 870593, Syncrude shall file with the Board operating procedures including normal and emergency start-up and shut-down procedures.

16. This approval, insofar as it pertains to matters of the environment, is subject to the approval of the Minister of the Environment, hereto attached as Appendix B to this approval, and insofar as it pertains to matters that affect land and resources that are the property of the Crown in right of Alberta, is subject to the approval of the Minister of Forestry, Lands and Wildlife, hereto attached as Appendix C to this approval, and to the terms and conditions therein contained.

17. (1) Attached hereto as Appendix D to this approval is the Order of the Lieutenant Governor in Council authorizing the granting of this approval.

(2) This approval is subject to the terms and conditions prescribed by the Order of the Lieutenant Governor in Council set out in Appendix D.

18. (1) The Board may,

(a) upon its own motion, or

(b) upon the application of an interested person,

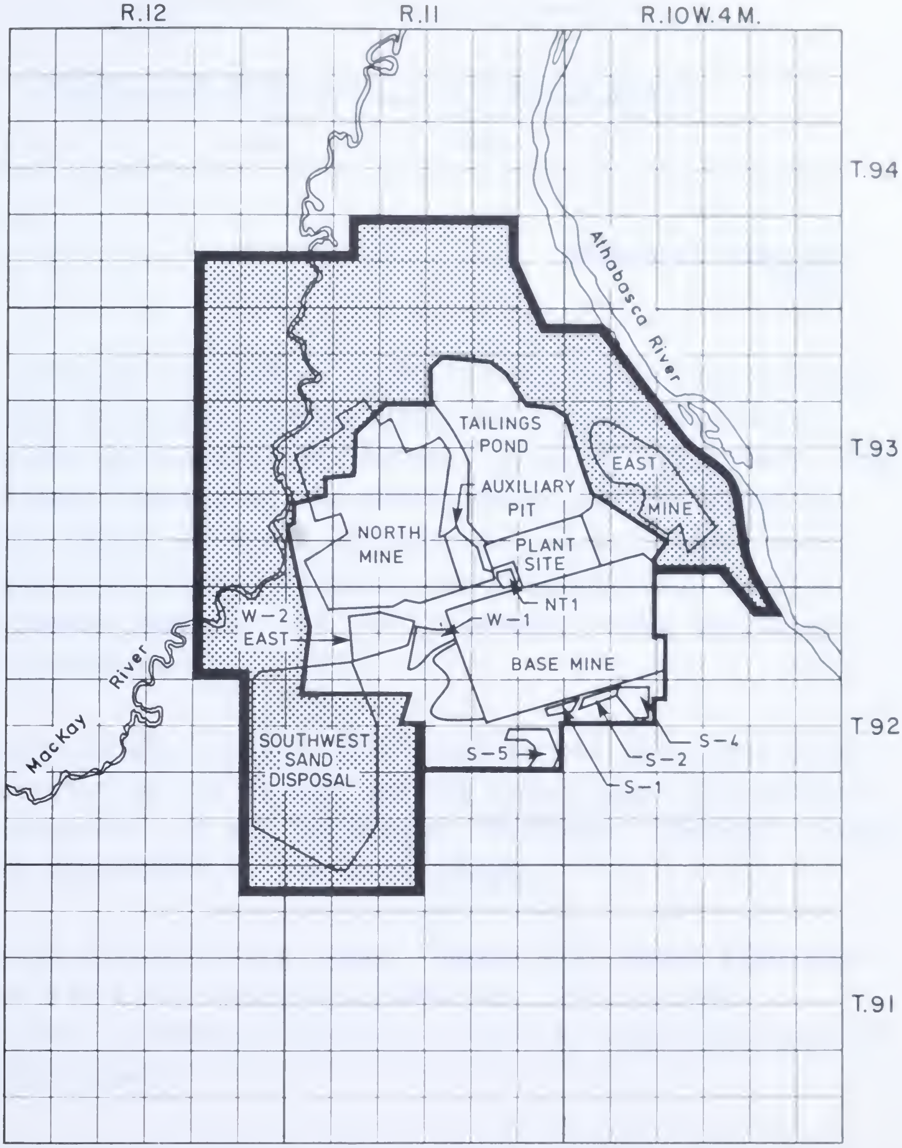
rescind or amend this approval at any time if, in the opinion of the Board, circumstances so warrant.

(2) This approval expires on 31 December 2018 unless rescinded before that date or, upon application by the Operator, a later date is approved by the Board.

19. Board Approval No. 4973 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this

MEMBER OF THE
ENERGY RESOURCES CONSERVATION BOARD



SYNCRUDE OIL SANDS PROJECT
MILDRED LAKE AREA

ERCB

APPENDIX A TO APPROVAL NO. 5641

PREVIOUS APPROVAL NO. 4973

AREA OF CHANGE

REFERENCE

PROJECT AREA

APPROXIMATE AREAS OF MINES AND SURFACE FACILITIES

W, S — APPROVED DISCARD SITES

APPENDIX B TO APPROVAL NO. 5641

Department of the Environment

M I N I S T E R I A L   A P P R O V A L

No.   ERCB

Edmonton, Alberta
1988

Pursuant to section 14 of the Oil Sands Conservation Act, I, Vance MacNichol, Deputy Minister of the Environment, hereby approve Application No. 870593, dated 27 April 1987, from Syncrude Canada Limited to the Energy Resources Conservation Board in the matter of Board Approval No. 4973, insofar as it affects matters of the environment, such application to be granted by Board Approval No. 5641, subject to the following terms and conditions:

1. Syncrude Canada Limited shall comply with the Clean Water Act Licence No. 83-WL-210 and the Clean Water Act Licence No. 84-AL-057, or any subsequent amendments thereof, issued by the Department of the Environment.

2. Syncrude Canada Limited shall comply with Water Resources Permit #1778 and Interim Licence No. 7795, or any subsequent amendments thereof, issued by the Department of the Environment.

3. Syncrude Canada Limited shall comply with the Development and Reclamation Approval No. OS-1-78, or any subsequent amendment thereof, issued by the Department of the Environment.

DEPUTY MINISTER OF THE ENVIRONMENT

APPENDIX C TO APPROVAL NO. 5641

Department of Forestry, Lands and Wildlife

MINISTERIAL APPROVAL

No. ERCB

Edmonton, Alberta
1988

Pursuant to section 14 of the Oil Sands Conservation Act, the Minister of Forestry, Lands and Wildlife hereby approves Application No. 870593, dated 27 April 1987, from Syncrude Canada Limited to the Energy Resources Conservation Board in the matter of Board Approval No. 4973, insofar as it affects land and resources that are the property of the Crown in right of Alberta, such application to be granted by Board Approval No. 5641.

MINISTER OF FORESTRY, LANDS AND WILDLIFE
Per: F. W. MCDOUGALL,
DEPUTY MINISTER

APPENDIX D TO APPROVAL NO. 5641

ORDER IN COUNCIL

APPROVAL AND ORDERED, O.C.

LIEUTENANT GOVERNOR EDMONTON, ALBERTA

Upon the recommendation of the Honourable the Minister of Energy, the Lieutenant Governor in Council, pursuant to section 14(2) of the Oil Sands Conservation Act, authorizes the Energy Resources Conservation Board to grant Approval No. 5641 in the attached form and subject to the terms and conditions contained in Attachment 1.

ATTACHMENT 1 TO O.C. NO. ____________

Pursuant to section 14(2) of the Oil Sands Conservation Act, the Order of the Lieutenant Governor in Council authorizing the issuance of an approval by the Energy Resources Conservation Board to Syncrude Canada Ltd. (hereinafter called "the Operator") is subject to the following terms and conditions:

1. The Operator shall satisfy the Minister of Economic Development, prior to the commencement of construction and thereafter throughout the term of the permit, with respect to the use, wherever practicable in the project, of Alberta engineering and other professional services; Alberta tradesmen and other construction personnel; and equipment, materials and supplies from Alberta.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

Decision D 88-8

CHEVRON CANADA RESOURCES LIMITED
GAS PLANT EXPANSION
POUCE COUPE FIELD — Application 871060

DOME PETROLEUM LIMITED
RATEABLE TAKE
POUCE COUPE KISKATINAW D POOL — Application 880038

1 INTRODUCTION

1.1 Applications

Chevron Canada Resources Limited submitted Application 871060 under section 26 of the Oil and Gas Conservation Act (the Act) for approval to increase the maximum capacity of its Pouce Coupe sweet gas processing plant located in legal subdivision (Lsd) 6 of section (Sec) 30, Township (Twp) 79, Range (Rge) 11, west of the 6th meridian (W6M) (the 6-30 plant) by 250 thousand cubic metres per day (10^3 m^3/d) of raw gas. If approved, the plant would process a maximum of 560 x 10^3 m^3/d of raw gas from which 546 x 10^3 m^3/d of sales gas and 64 m^3/d of liquefied petroleum gases (LPG mix) would be recovered.

Dome Petroleum Limited, on behalf of itself, Conwest Exploration Company Limited, Drummond Oil and Gas Ltd., Hamilton Brothers Canadian Gas Co. Ltd., and Shell Canada Limited (Dome et al), submitted Application 880038 under section 23 of the Act for an order

- to restrict the total volume of gas that may be produced from the Pouce Coupe Kiskatinaw D Pool (the D Pool) from the three wells, DOME ET AL GORDONDALE 11-19-79-11 (W6M), CHEVRON POUCE COUPE 6-30-79-11 (W6M), and DOME ET AL POUCE COUPE 15-24-79-12 (W6M), and

- to distribute the volume of gas so produced among the three wells named.

1.2 Hearing

The applications were considered at a public hearing in Calgary, Alberta, on 14 and 15 March 1988, with Board Members G. J. DeSorcy, P.Eng., F. J. Mink, P.Eng., and Acting Board Member C. A. Langlo, P.Geol., sitting.

Those who appeared at the hearing and abbreviations used in this report are listed on Table 1.

1.3 Interventions

Interventions to Chevron's Application 871060 for expansion of its gas plant were filed by Conwest, Dome, Drummond, Hamilton, and Shell. Dome represented the interveners at the hearing. In addition, Shell presented final argument. Chevron also filed an intervention to Dome's Application 880038.

1.4 Background

The D Pool is a non-associated gas pool currently defined by Board Order G 5567 as underlying 16 sections in Twps 79 and 80, Rges 11 and 12, W6M, as shown on Figure 1. A list of the wells included in the pool, the licensee, finished drilling date, and current status of each well, and the abbreviations used in the report are shown on Table 2. The D Pool was discovered in 1974 by the drilling of the 10-26 well and, as currently defined, includes 12 wells. Shell, Star, and Suncor are the licensees of the wells in the western portion of the D Pool, while Chevron and Dome are the licensees of the wells in the eastern portion of the pool. Additionally, Conwest, Drummond, and Hamilton, as well as Dome, have an interest in the 11-19 well, while Shell and Dome have an interest in the 15-24 well.

Production from the D Pool began in 1977 from Shell's 7-8 well in the western area of the pool. The remaining six producing wells began operations during 1986 and 1987. Cumulative gas and condensate production from the pool to December 1987 totalled 373.7 million (10^6) and 840.1 m^3, respectively. Gas from the western area of the pool is processed at two Shell plants located at the 7-8 well, and at a Star plant located at the 2/11-34 well. Gas from the eastern area of the pool is processed at two additional gas plants. Chevron received approval for the 6-30 plant in October 1986, and began producing the 6-30 well in May 1987; Dome received approval for a plant located at the 11-19 well (the 11-19 plant) in June 1987, and has been producing the 11-19 well since December 1987.

Chevron submitted Application 871060 for approval to expand the 6-30 plant in July 1987. Because of concerns expressed by other area producers, the application was advertised and objections were received from Dome, Drummond, and Shell. The objections were centred around the issues of equitable production from the D Pool and access to processing capacity. The interveners indicated that if Application 871060 was approved, they would file an application to limit production from the 6-30 well, which was identified in Application 871060 as the sole source of raw gas feedstock. Dome et al subsequently submitted Application 880038 for a rateable take order as described above. To the extent that

an order limiting production from the 6-30 well could impact on the need for the proposed increase in plant processing capacity, the Board decided to consider both applications at a public hearing.

2 ISSUES

The Board considers the issues to be

- the delineation of the D Pool,
- the proposal for additional processing capacity at the 6-30 plant,
- the need for a rateable take order, and
- the basis for distributing production and the details of a rateable take order, if one is to be issued.

3 POOL DELINEATION

3.1 Views of Chevron

Chevron submitted that the eastern portion of the D Pool consists of two distinct sand units: an upper unit, the Kiskatinaw A sand (the A sand) and a lower unit, the Kiskatinaw B sand (the B sand), which are in natural communication. It argued that, although information from the 11-19 and 6-30 wells shows the zones to be separated by a non-pay interval, communication likely exists away from the wellbore. Chevron submitted that communication could be due to fractures resulting from faulting in the area, or more likely, a result of the deposition of the A sand directly over the B sand, which is possible in this type of depositional environment. Additionally, Chevron noted that, because the permeability and productivity of the A sand in the 6-30 well is about 40 to 50 times that of the B sand, the latter sand would not contribute significantly to production taken from the well. It attributed the decline in pressures observed in the B sand at the 11-19 and 15-24 wells to production from the A sand in the 6-30 well, and concluded that the sands are therefore in communication. Chevron also noted that a hydrostatic gradient of 2.3 kilopascals per metre, calculated on the basis of initial pressure differences between the A and B sands in the 6-30 well, is similar to a gas gradient, and could indicate that the two sands are in communication through a gas column. However, during cross-examination, Chevron conceded that the gas gradient could be explained by the communication which was evident between the sands in the 6-30 well during testing.

Chevron mapped the A sand net gas pay in the 6-30 well in a channel configuration extending to the southeast as shown on Figure 2. It noted that an A-sand equivalent is also present in the 11-19 and 6-15 wells but is tight and unproductive.

Chevron mapped the B sand in the 6-15, 11-19, 6-30, and 15-24 wells as shown on Figure 3. It extended the eastern portion of the pool in the B sand to include the 6-15 well, which it interpreted as a continuation of deposition from the northwest. In Chevron's view, logs showed the B sand in the 6-15 well as having marginal porosity and water saturation which justified the assignment of 3 feet of gas pay. It argued that drill stem tests did not show the B sand in the 6-15 well to be wet, since the tests were misrun, and only water cushion and mud were recovered.

Chevron positioned the western boundary of the B sand isopach by means of a permeability barrier inferred from pressure data only, since geological data do not confirm the presence of a barrier, and it excluded both the 11-25 and 10-26 wells from the isopach. Chevron submitted that the pressure of the B sand at the 10-26 well showed that the well was not in the same pool as the 11-19, 6-30, and 15-24 wells, and perhaps not in the same pool as the 11-25 well. Chevron noted that a recent measurement at the 11-25 well showed the pressure at that well was somewhat lower than those measured at the 11-19 and 15-24 wells, which suggested that the 11-25 well was in a different pressure system. Chevron conceded that it would also be possible to conclude that the pressure decline at the 11-25 well resulted from production of the 11-19 and 6-30 wells, and that all three wells could be mapped into the same pool. However, it also suggested that the pressure decline at the 11-25 well could be due to production from the 2/11-34 well located northwest of the 11-25 well.

Chevron mapped both the A and B sands as limited by a fault to the north of the 6-30 well, by a lack of porosity in the wells in Lsd 10-18 and 10-20-79-11 W6M (the 10-18 and 10-20 wells, respectively), and by the interpreted geometry of the channel trend.

Chevron estimated the total gas in place of the A and B sand pools by material balance and volumetric analyses to be 3400 x 10^6 and 3040 x 10^6 m^3, respectively. It did not provide an estimate of the remaining recoverable reserves of the pools. The detailed bases for Chevron's reserves calculations are outlined in its intervention to the Dome et al application.

3.2 Views of Dome et al

Dome et al recognized and mapped the A and B sands as two separate pools and concluded that there is no direct geological or pressure data which show that communication exists between the sands.

Dome et al noted that the 6-30 well is the only well in the area which encountered productive gas pay in the A sand. Accordingly, it depicted the A sand pool as a single-well pool containing only the 6-30 well, as shown on Figure 2.

Dome et al mapped the B sand pool as containing the 11-19, 6-30, 15-24, and 11-25 wells, as shown on Figure 3. It noted that a decline in pressure at the 11-19, 15-24, and 11-25 wells in response to production from the 6-30 well confirmed that all of the wells are in the same pool. Dome et al interpreted the B sand in the 6-15 well as wet and structurally higher than the B sand in the 11-19 well, and concluded that a barrier exists between the two wells.

Dome et al submitted that there is a reduction of both permeability and porosity of the B sand in the 10-26 well. Further, the pressure data for the well indicate that the well is not responding to production from the 6-30 well, and is either in a different pressure system than the other wells in the B sand, or became depleted during production testing in 1975, which suggests the well is not in communication with any nearby well.

Dome et al also limited both the A and B sand pools by a fault to the north of the 6-30 well, and by the absence of porous sand to the south and east in the 10-18 and 10-20 wells.

On the basis of the above evidence, Dome et al requested that the Board redesignate the D Pool to recognize the existence of a separate pool in the southeastern area of the currently-defined pool.

Dome et al did not provide an estimate of the total reserves of the A and B sand pools as mapped. However, it estimated the gas in place and remaining recoverable reserves underlying sections 19 and 30-79-11 W6M and 24-79-12 W6M to be 1701 x 10^6 and 1300 x 10^6 m^3, respectively. Other details of Dome's reserves calculations are outlined in its application.

3.3 Views of the Board

The Board has reviewed the evidence regarding pool delineation, and agrees that the D Pool is less extensive than currently designated. The Board notes the uncontested evidence given at the hearing that the A sand is productive only at the 6-30 well and therefore views the areal extent of the B sand, defined by geological and pressure data, as the limiting factor in delineation of the pool.

The Board believes that the available evidence suggests that there is at least limited natural communication between the A and B sands. Although the geological evidence is inconclusive, the observed pressure decline in the B sand at the 11-19, 15-24, and 11-25 wells is consistent with communication between the sands. However, in the Board's opinion, there remains some question as to the extent of the communication.

The Board agrees that both geological and pressure data clearly indicate that the 11-19, 6-30, and 15-24 wells are in the same pool. The evidence regarding the eastern and southern limits of the pool would

not, in the Board's view, justify including any sections east of sections 19 and 30-79-11 W6M or south of sections 19-79-11 W6M and 24-79-12 W6M within the pool. The Board notes that the B sand in the 6-15 well has not been confirmed as gas-bearing and is therefore not likely an extension of the pool to the southeast as interpreted by Chevron.

The Board agrees with Chevron and Dome et al that the pressures taken at the 10-26 well show the well is not in the same pressure system as the 11-19, 6-30, and 15-24 wells, and should not be included in the same pool as these wells. Additionally, the Board is of the view that pressure and production data imply communication between the B sand in the 11-25 well and the sands encountered by the 6-30 well. The data also suggest that the 2/11-34 well is likely too far away to account for the pressure decline observed at the 11-25 well, as suggested by Chevron. The Board concludes that section 25-79-12 W6M represents the western limit of the pool.

In summary, the Board believes it appropriate to redesignate the current D Pool to include only sections 19 and 30-79-11 W6M and sections 24 and 25-79-12 W6M, as shown on Figure 1. The remaining eastern portion of the pool will be reviewed and new pools will be defined as appropriate in the routine manner.

The Board also considers it useful to note that the remaining volumetrically-determined recoverable reserves of the revised D Pool are about 1030×10^6 m^3.

4 THE PROPOSED ADDITIONAL PROCESSING CAPACITY AND THE NEED FOR A RATEABLE TAKE ORDER

4.1 Views of Chevron

Chevron stated that it has the right to produce its reserves as it sees fit, subject only to any overriding conservation or environmental considerations, and that no such concerns exist in this instance.

The applicant submitted that it had an immediate need for the additional gas volumes, to offset the cost of purchasing gas to supply its miscible flood demands. Further, since the 6-30 well is physically capable of producing at rates up to 560×10^3 m^3/d, Chevron's need for additional gas volumes could be partially met by increased throughput at its Pouce Coupe gas plant.

It was Chevron's evidence that since there is no capacity available at either the Dome 11-19 plant or its 6-30 plant to process additional volumes, expansion of the 6-30 plant was warranted. However, Chevron pointed out that its plant had originally been designed with provisions

for a possible future expansion. Accordingly, only minor plant modifications would be required in order to accommodate the proposed increase in throughput.

Chevron stated that it expected that its 6-30 plant would remain operational for at least 10 years and that the plant could likely operate at the applied-for capacity of 560 x 10^3 m^3/d until about 1994. Chevron indicated that it intended to maintain the plant at capacity by installing compression or tying in future wells. As such, Chevron stated that it had very little expectation that other producers' gas could be processed at its expanded plant until after 1994. However, it would consider equity participation in any further plant expansion and had offered capacity in the existing plant on a best-efforts basis.

Chevron pointed out that the Dome et al wells had been drilled in 1981 but that no plant development was pursued until 1986. Further, it was Chevron's position that Dome et al was aware that it was evaluating construction of a gas plant as early as April 1986. In December 1986, Chevron had requested details of Dome et al's processing requirements and later, in September 1987, Chevron made an offer to process gas for Dome et al on a best efforts basis; however, no response was received.

Chevron submitted that Dome et al had been provided with a reasonable opportunity to develop its reserves but had not chosen to do so. The applicant argued that denial of its application would dampen the development of gas reserves, slow economic activity, and establish an unhealthy precedent whereby a party could frustrate a second party's development plans by choosing not to develop its own reserves.

Further, Chevron stated that the objections of Dome et al, which were centred around the issue of equitable production and potential drainage, were not relevant to consideration of a gas processing plant application. Chevron maintained that the proper criteria upon which gas processing schemes should be judged were: need, and whether the scheme represented efficient, orderly, and economic development in the public interest. To its knowledge, in no other gas plant application had the issue of appropriate rates of production had any bearing on these public interest considerations.

Chevron did not agree with the intervener's position that approval of its application would force Dome et al to expand its processing capacity in order to recover its share of reserves, thus resulting in needless expense and duplication of facilities. Chevron pointed out that production from the intervener's wells is presently constrained, to some extent, by the capacity of Dome's 11-19 gas plant. This, coupled with Chevron's intention to drill additional wells in the area, led it to conclude that there may be a need for additional processing capacity beyond what is currently proposed.

Chevron re-emphasized that it had offered capacity to the interveners in the proposed 6-30 plant expansion on a best-efforts basis and an equity position in any further plant expansions. Chevron stated that it had no further obligations in that regard and expected that other area producers would take whatever steps were prudent to protect their interests in the area. Chevron asked that its application be approved since it had demonstrated a need for additional gas volumes, could obtain the additional volumes from the 6-30 well, and could accommodate the increased throughput at the 6-30 plant with only minor modifications and at minimal cost. Furthermore, Chevron concluded that its plant would efficiently conserve valuable resources and provide royalty revenue to the Province and was therefore, in the public interest.

Chevron opposed Dome's rateable take application on the basis that Dome has not demonstrated that drainage is presently occurring and will occur in future, or that it has not had, and will not have, the opportunity to produce its share of gas from the D Pool.

With respect to drainage matters, Chevron pointed out that, although pressure data indicated that the Dome et al reserves had been drained prior to the commencement of production from the 11-19 well, there was no evidence to suggest that drainage was presently occurring. Further, Chevron contended that drainage may never occur in future, even if the 6-30 plant expansion proceeds, because: the plant may not be capable of operating at the expected volumes, the 6-30 well may not be capable of filling the plant, or gas processed at the plant may be restricted by a limitation in pipeline capacity to market. Chevron argued that the Dome et al application is premature in that Dome et al should have waited until such time as it had obtained evidence of drainage following approval of Chevron's application.

Chevron argued that Dome et al has not been denied the opportunity to produce its share of gas reserves from the D Pool. Dome et al had chosen not to develop its reserves until Chevron had drilled its well. Further, Chevron had made an offer to process Dome et al gas on a best-efforts basis but did not receive a response to the offer. Chevron contended that Dome et al also had the opportunity to size the 11-19 plant to allow for future expansion, but had not chosen to do so, possibly because of the availability of an existing plant which could be, and subsequently was, moved to the 11-19 location.

Chevron contended that Dome et al will continue to have the opportunity to obtain its share of production from the D Pool, even if the 6-30 plant expansion is approved. Chevron noted Dome et al's acknowledgement that it had no market restrictions. Additionally, Dome et al continues to have the option of expanding the existing 11-19 plant. Chevron conceded that the return on the incremental investment needed to expand the 11-19 plant may be negative, but the return on the total investment is still economically attractive, particularly if a larger reserves base is used in the analysis.

With respect to transportation, Chevron noted that sales gas pipeline capacity is indeed a variable factor, but it is the same for all producers. Dome et al has had the same opportunity as other producers to apply for additional firm capacity, and continues to have that opportunity; additionally, interruptible capacity is available for many months of the year.

Finally, Chevron submitted that the issuance of a rateable take order would have a negative impact on Chevron by restricting the development of reserves for which it has a demand. Chevron concluded that, as Dome et al has not conclusively demonstrated present and future drainage of its reserves, or lack of past or future opportunity to produce an equitable share of reserves from the D Pool, the application for a rateable take order should be denied.

4.2 Views of Dome et al

Dome et al stated that it opposed the Chevron plant expansion and submitted the rateable take application on the basis that the proposed expansion would result in drainage of its reserves in the southeastern portion of the D Pool.

Dome et al submitted data showing a decline in pressure at the 11-19 and 15-24 wells and attributed the decline to production taken from Chevron's 6-30 well, which had been operating since May 1987. Dome et al said that the drainage had been alleviated to a degree when it installed the gas plant at the 11-19 well and began producing the well in December 1987. However, Dome argued that because drainage had occurred from May to December 1987, and since approval of the Chevron application would result in a similar production differential, drainage would again occur.

Dome et al stated that it is the Board's duty to ensure that development is undertaken in an efficient, orderly, and economic manner, and that each reserves owner is afforded the opportunity to recover his share of production, which would not be the case if the Chevron application were approved.

Dome et al contended that development in the area to date had occurred in a haphazard manner. It pointed out that it had not been made aware of Chevron's intention to build a processing plant at the 6-30 site until after the plant was approved and under construction. At that time, Chevron advised Dome et al that it was unwilling to modify its plant design. Dome et al confirmed Chevron's offer to process gas volumes on a best-efforts basis, or alternatively to allow Dome et al an equity position in a possible expansion of the 6-30 plant. However, the offers made by Chevron were unacceptable to Dome et al, since no spare capacity was forecast to exist and expansion of the 6-30 plant might never have taken place. Subsequently, Dome et al had attempted to obtain processing capacity in the Shell-Gordondale gas plant located in

the northwest quarter of section 24-79-11 W6M. However, since the cost of pursuing this option would exceed the cost of installing its own plant, Dome applied for and received approval to build the 11-19 plant.

As a result, two separate plants had been constructed only 800 metres apart at about twice the capital cost of a larger joint-venture scheme. Dome et al submitted that, although the two-plant scenario did not represent the most efficient, orderly, or economic approach to pool development, it had allowed Dome et al to recover roughly its share of reserves when each plant was operated up to its current capacity.

Dome et al considered the alternatives of increasing its production by debottlenecking or expansion of the 11-19 plant as impractical or unreasonable for several reasons. It argued that the recoverable reserves of about 1300 x 10^6 m^3 associated with the 11-19, 6-30, and 15-24 wells did not justify the additional costs of expanding the capacity of the plant. Dome et al noted that, with the 11-19 and 6-30 plants processing to current or expanded capacity, the recoverable reserves of the pool would be produced in about 3 to 6 years. Further, expansion of the plant, when considered in light of the volume of the producible reserves of the D Pool, would result in negative incremental economics and reduce the present value of the reserves. Additionally, if Dome et al did obtain the Board's approval to expand the 11-19 plant, by the time the capacity was on stream in about the summer of 1989, the deliverability of the Dome et al wells would not be sufficient to fill the expanded plant without the addition of significant and costly compression.

Dome et al also pointed out that pipeline capacity to transport marketable gas from the area is presently restricted. It said that it had firm transportation capacity for about 280 x 10^3 m^3/d, but that it would be 2 or 3 years before it could obtain additional firm capacity. By the time additional capacity was available, the deliverability of the wells would again not be sufficient to use the capacity without the installation of costly compression facilities. Dome et al concluded that although a theoretical opportunity existed for it to obtain an equitable share of production from the D Pool, the opportunity was meaningless from a practical perspective.

Dome et al recommended denial of the Chevron application on the basis that any increase in capacity at the 6-30 plant would either result in inequitable drainage of its reserves, or force it to proceed with alternatives which would be economically unattractive in order to obtain its share of pool reserves. However, Dome et al also suggested that if the rateable take and gas plant expansion applications were both approved, its equity in the pool would be protected, and Chevron would have the opportunity to fill the increased capacity at the 6-30 plant by production from other wells or pools.

4.3 Views of Shell

Shell indicated that it agreed with most of Dome's viewpoints on Applications 871060 and 880038. However, it noted that it has a working interest in the 15-24 well only. Its position, accordingly, is that the rateable take order should be approved, regardless of whether Chevron's application is approved or denied, in order to afford each owner the opportunity to produce its equitable share of the pool's reserves.

4.4 Views of the Board

4.4.1 Gas Plant Expansion

The Board notes that there are five gas plants processing Kiskatinaw gas in the area of application. The Board is concerned that the obvious lack of communication and co-operation on the part of area producers has led to unnecessary duplication of facilities, increased land use impacts, additional capital expenditures, and increased administrative burden. The Board encourages an open exchange of information and joint planning wherever possible, and expects that proponents of energy developments will recognize the needs of other producers when making applications to the Board, and will be prepared to speak to those needs.

The Board notes the intervener's suggestion that Chevron knowingly constructed a larger facility at the 6-30 well than originally approved by the Board, and that this allowed Chevron to seek an "easy" approval of its expansion application. In that regard, the Board notes that the facility as constructed was not specifically approved by the Board in that the final design included certain oversized equipment which would facilitate expansion. The Board would prefer that such provisions be addressed at the time an application is made.

In any case, deviations from the original design concept in the application to allow for possible expansion would be undertaken by an operator, in this case Chevron, at its own risk. Regardless of the capability of the facility, the Board considers process operations to be limited by the terms and conditions of the original plant approval. Any subsequent increase in capacity or amendment of the approval conditions would necessitate a further application to the Board. The Board reaffirms that it would not be significantly influenced towards approval of such applications simply because the equipment is already in place. Further, in the case of competing applications or other disputes where economic analysis is needed, the cost of the modifications would normally be deemed by the Board to be those which would have been needed if the provision for expansion had not been built into the original facility.

Notwithstanding the above comments, the Board is satisfied that operation of the 6-30 plant at increased throughput would provide for the conservation and upgrading of a Provincial resource. The Board also notes that Chevron has a ready market for the proposed increased volumes, and that the 6-30 well appears to be capable of supplying the additional gas. Chevron's application is technically sound and has adequately addressed the issue of environmental protection.

In the Board's view, the reduced life of the plant and pool that would result from approval of the application (about 8 years) is less than would typically be expected, but is not so unreasonably short as to cause refusal of the application. (The Board considers Dome et al's estimate of pool life of 3 to 6 years as unduly pessimistic because it does not account for declining producing rates.) Further, the proposed increased production from the 6-30 well should not result in any reservoir damage which could reduce the amount of gas that could ultimately be recovered from the pool. The Board is therefore satisfied that there are no conservation reasons for not approving Chevron's application at this time. However, if in future it appears that high withdrawal rates from the pool may jeopardize conservation, the Board would re-examine the matter and, if appropriate, take action independently of any application from industry to limit rates of production from wells in the pool.

Finally, the Board does not consider the matter of possible drainage and the need for a rateable take order, as raised by Dome, to be an issue which would cause the Board not to approve an otherwise proper gas processing plant application. In saying this, however, the Board recognizes that its decision regarding the Dome application could infuence whether Chevron would proceed with its plant expansion.

In summary, the Board concludes that Chevron has satisfactorily addressed all of the matters pertinent to its application, and the Board is therefore prepared to approve it.

4.4.2 Rateable Take

The Board considers the issuance of a rateable take order to be a very significant action on its part because it has the potential to override contractual arrangements put in place through normal business practices. Consequently, before approving an application for a rateable take order, the Board believes it must be convinced that a limitation of production rates is necessary because a well owner is being deprived of an opportunity to produce his share of the reserves of a pool. To demonstrate that an owner is not producing his share of reserves, the Board takes the position that the owner must be able to show that drainage is actually occurring or that it can be expected to occur with a very high degree of certainty. Additionally, the drainage must be as a result of the owner not having an opportunity to have produced his

share of gas. In a case where the only limitation on production is the lack of wells or well capability, the Board considers that a producer is not being denied the opportunity to obtain his equitable share.

The Board notes that there are no market restrictions to prevent Dome et al from producing its share of pool reserves. Dome et al stated that transportation of its gas could be a problem if it expanded the 11-19 plant. However, no evidence was presented to indicate that Dome could not obtain additional pipeline capacity at least on an interruptible basis for the short term, and firm capacity in the next 2 or 3 years, or that such capacity as is available would not allow Dome et al to produce its share of pool reserves.

The primary matter for consideration relates to limited processing capacity at the 11-19 plant, and the resulting possibility of drainage if the Chevron 6-30 plant is expanded. The Board notes Dome's evidence that its reserves were being drained prior to the commencement of production from the 11-19 well. However, there was no evidence that drainage is occurring at the present time. Further, while Dome discussed the likelihood that its reserves would be drained by additional production from the 6-30 well, it did not present any substantial analysis to support its arguments.

In the Board's view, although some drainage might be expected if the 6-30 well produces at much higher rates, such drainage may not be significant because of the possibility of limited communication between the A and B sands and the differences in productivity of the two sands. Indeed, depending on the pool configuration and its flow characteristics, there could be no drainage taking place.

In view of the foregoing, the Board is unable to conclude that Dome is being or would definitely be deprived of the opportunity to produce its share of pool reserves if additional gas is taken from the 6-30 well. Accordingly, the Board is not prepared to approve Dome's rateable take application. If in future Dome is able to substantiate that drainage is occurring and that it is not able to produce its share of gas from the pool because of limited processing capacity which could not be economically expanded, the Board would be prepared to consider a further application. If Chevron proceeds with its proposed expansion, it could face the risks that at some future date the producing rates for wells in the pool might be limited, or that it might be required to share the capacity of the 6-30 plant with other producers.

5 BASIS FOR DISTRIBUTING PRODUCTION AND DETAILS OF A RATEABLE TAKE ORDER

Because the Board does not believe it appropriate to issue a rateable take order at this time, there is no need to address the method of distributing production among the wells in the pool or the details of the proposed order.

6 DECISION

For the reasons noted above, the Board

- approves Application 871060, and
- denies Application 880038, without prejudice to any subsequent application that may be submitted.

DATED at Calgary, Alberta, on 17 June 1988.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

G. J. DeSorcy, P.Eng.
Chairman

F. J. Mink, P.Eng.
Board Member

C. A. Langlo

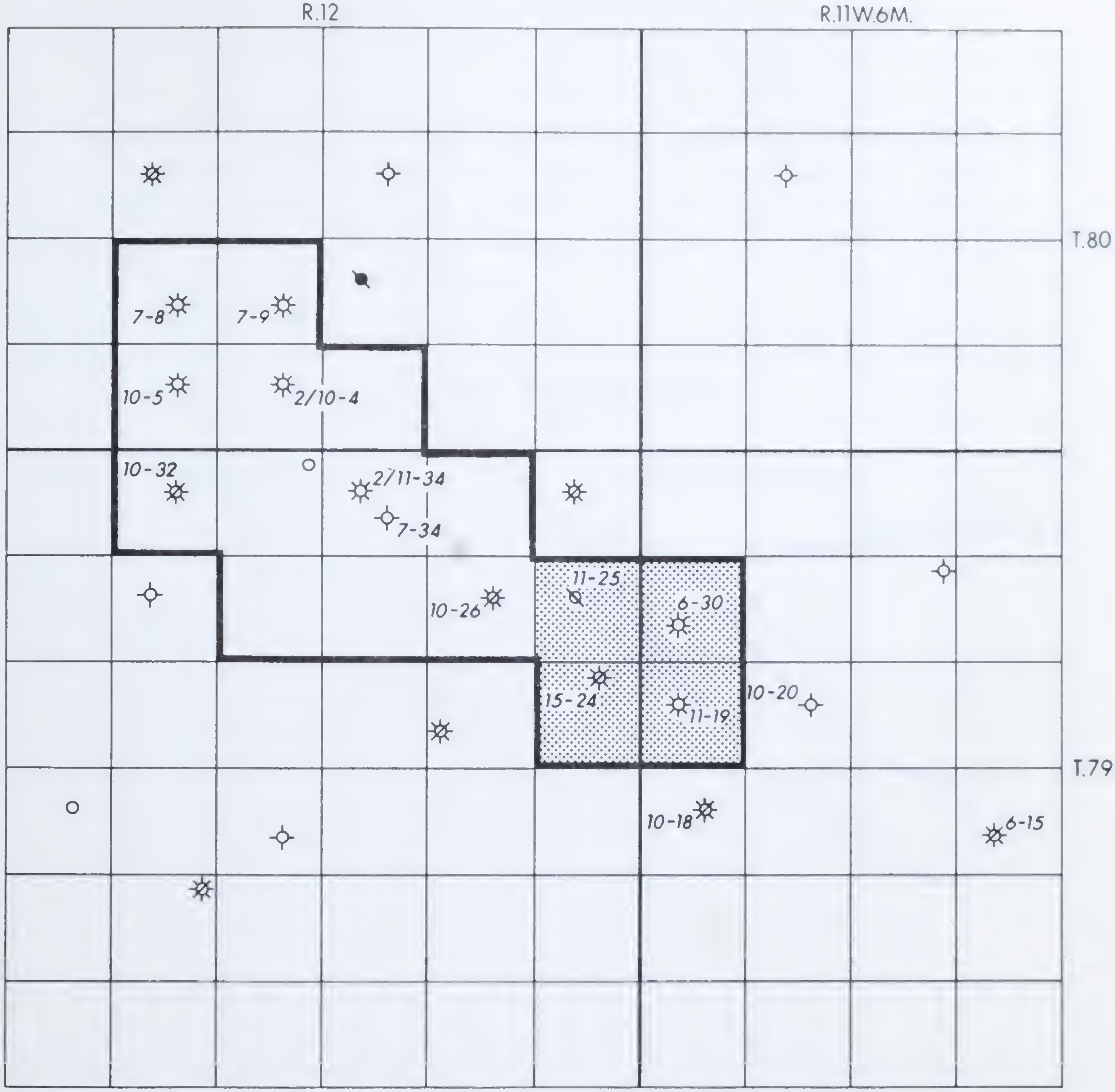
C. A. Langlo, P.Geol.
Acting Board Member

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Chevron Canada Resources Limited (Chevron) B. K. O'Ferrall	W. H. Armstrong, P.Eng. A. R. Bamsey, P.Eng. G. F. Caldwell, P.Geol. W. A. Scott C. B. Vander Linden, P.Eng.
Conwest Exploration Company Limited (Conwest) S. L. Koroluk, P.Eng.	
Dome Petroleum Limited (Dome) R. A. Neufeld D. E. Crowther	B. C. Carrigy, P.Geol. D. L. Pearce, P.Eng. N. T. Topolnyski B. J. Waters, P.Eng.
Drummond Oil & Gas Ltd. (Drummond) B. K. Fung, P.Eng.	
Hamilton Brothers Canadian Gas Company Ltd. (Hamilton) W. J. Montgomery, P.Eng.	
Shell Canada Limited (Shell) E. Decter	
Energy Resources Conservation Board staff M. J. Bruni K. Fisher, C.E.T. D. G. Harris, P.Geol. L. S. Fillion, C.E.T.	

TABLE 2 WELLS INCLUDED IN THE POUCE COUPE KISKATINAW D POOL

Well Location (Abbreviation Used in Report) (Lsd-Sec-Twp-Rge W6M)	Licensee (Abbreviation Used in Report)	Finished Drilling Date	Current Status, Date of Current Status
11-19-79-11 (the 11-19 well)	Dome	1981 04 24	flowing gas, 1987 12 06
6-30-79-11 (the 6-30 well)	Chevron	1985 12 27	flowing gas, 1987 05 10
15-24-79-12 (the 15-24 well)	Dome	1981 12 12	capped gas, 1983 04 15
11-25-79-12 (the 11-25 well)	Dome	1981 10 25	suspended undesignated, 1981 12 07
10-26-79-12 (the 10-26 well)	Dome	1974 11 14	capped gas, 1975 01 27
10-32-79-12 (the 10-32 well)	Suncor Inc. (Suncor)	1980 08 11	capped gas, 1980 09 12
7-34-79-12 (the 7-34 well)	Dome	1975 03 27	abandoned, 1975 04 01
11-34-79-12 (the 2/11-34 well)	Star Oil & Gas Ltd. (Star)	1984 09 10	flowing gas, 1986 08 22
10-4-80-12 (the 2/10-4 well)	Shell	1976 10 14	flowing gas, 1987 04 01
10-5-80-12 (the 10-5 well)	Star	1979 07 06	flowing gas, 1986 12 05
7-8-80-12 (the 7-8 well)	Shell	1976 11 28	flowing gas, 1977 12 29
7-9-80-12 (the 7-9 well)	Shell	1976 07 06	flowing gas, 1987 04 01



Capped gas

Flowing gas

Suspended oil

Suspended undesignated

Standing

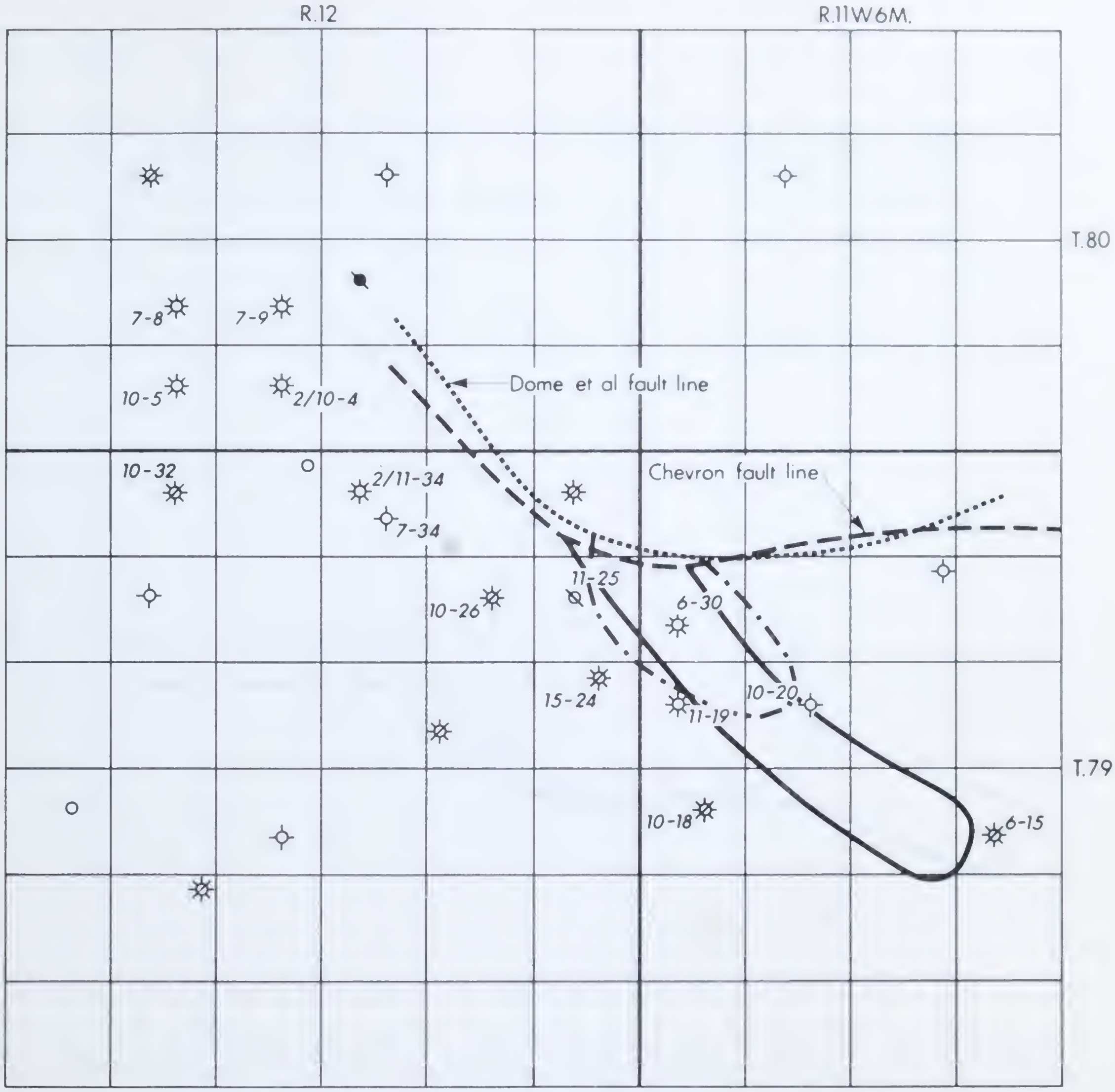
Abandoned

Existing Pouce Coupe Kiskatinaw D Pool by Board Order No. G5567

Revised Pouce Coupe Kiskatinaw D Pool

Well locations indicate Kiskatinaw Formation penetrations

FIGURE 1 POUCE COUPE KISKATINAW D POOL



Capped gas

Flowing gas

Suspended oil

Suspended undesignated

Standing

Abandoned

Chevron zero pay contour

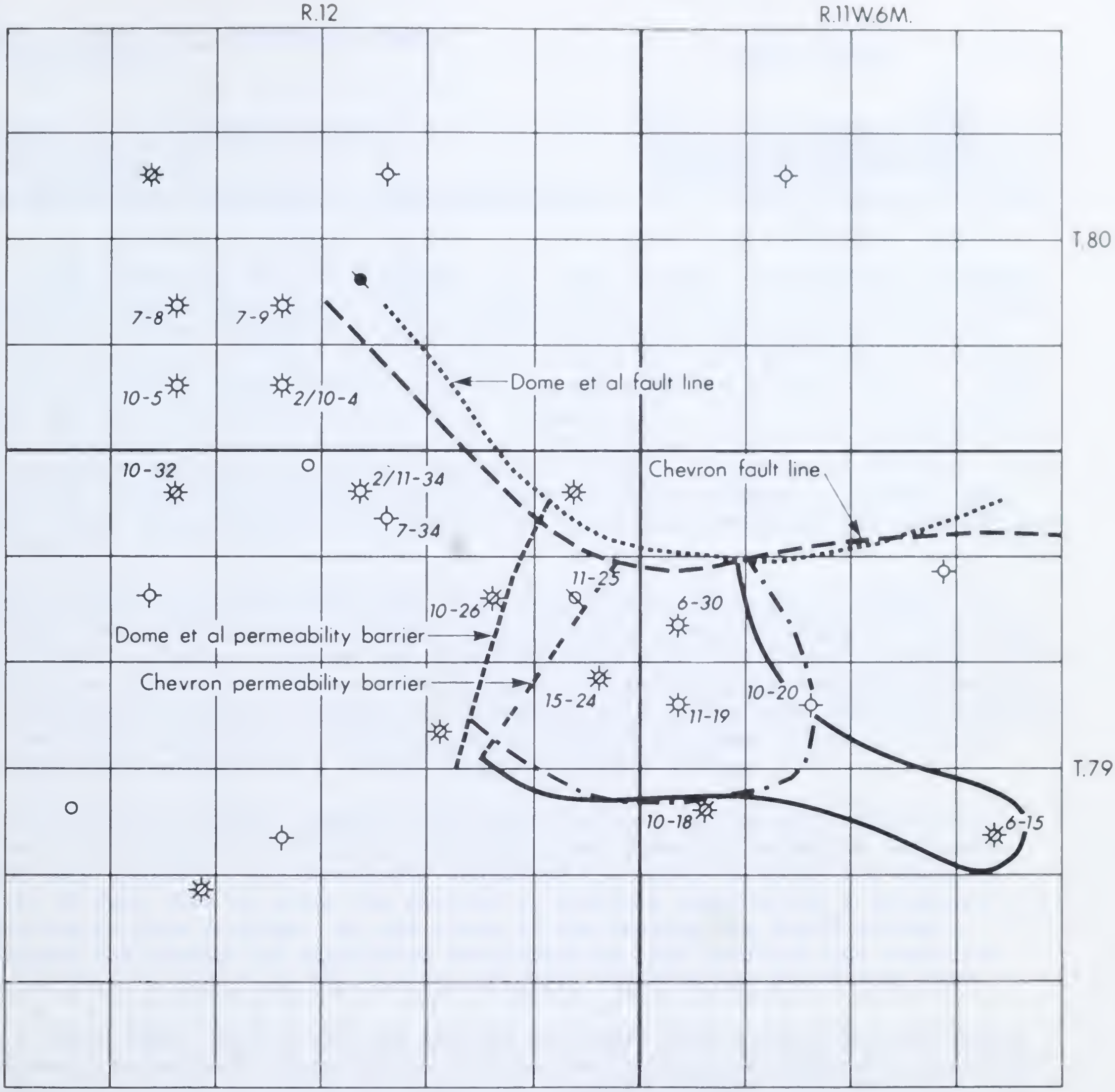
Dome et al zero pay contour

Well locations indicate Kiskatinaw Formation penetrations

FIGURE 2 POUCE COUPE KISKATINAW A SAND POOLS

D 88-8

ERCB



Capped gas

Flowing gas

Suspended oil

Suspended undesignated

Standing

Abandoned

Chevron zero pay contour

Dome et al zero pay contour

Well locations indicate Kiskatinaw Formation penetrations

FIGURE 3 POUCE COUPE KISKATINAW B SAND POOLS

D 88-8
ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CHEVRON CANADA RESOURCES LIMITED
ICG RESOURCES LTD.
GAS PROCESSING FACILITIES IN THE ACHESON FIELD

Application 871435
Application 880727
Interim Decision D 88-9

At a public hearing held in Edmonton, on 31 May through 2 June 1988, the Energy Resources Conservation Board (ERCB) considered an application by Chevron Canada Resources Limited (Chevron) to construct a gas processing plant designed to process a maximum of 500.0 thousand cubic metres per day (10^3 m^3/d) of raw gas and located on Chevron property adjacent to the existing ICG gas plant. At the same hearing the Board also considered an application from ICG Resources Ltd. (ICG) to expand its existing gas plant in section 2, township 53, range 26, west of the 4th meridian, to the same throughput level as the proposed Chevron facility. Both gas processing facilities were to be designed to produce the same volume of residue gas and ethane-plus mix from essentially the same raw gas sources.

Under normal operating conditions, there would be no emission of sulphur or sulphur compounds to the atmosphere from either of the proposed gas processing facilities. Chevron proposed to inject the 1116 m^3/d of hydrogen sulphide (1.51 tonnes per day (t/d) sulphur equivalent), recovered from the raw gas stream, to an underground formation either for disposal or in conjunction with its enhanced oil recovery operations. ICG proposed to recover the same volume of sulphur through the operation of a Lo-Cat sulphur recovery system.

In its closing argument Chevron reiterated the need for an early decision to allow it to complete the tight construction and operation schedule associated with this project. ICG conversely requested the Board to defer its decision until 15 June 1988 to allow the parties to continue negotiating a voluntary solution to this problem. At the close of the hearing the Board strongly endorsed the concept of negotiated settlement to this conflict and requested the parties to report on the results of their negotiations by 15 June 1988.

On 15 June 1988, Chevron and ICG advised the Board that a tentative settlement had been reached that would result in only the Chevron gas processing facility proceeding. On 6 July 1988 the Board was formally advised that formal agreement was reached between the parties for Chevron to purchase and salvage the ICG facility and that ICG had withdrawn its application to build an expanded plant.

The Board is satisfied that there is a need for additional gas processing capacity in the Acheson area and that only one facility is required. As the parties have reached an agreement respecting the construction of only the Chevron facility, the Board is prepared to approve that facility as described in Chevron's application.

The Board is satisfied that the Chevron proposal respecting the gas processing facility is technically and environmentally satisfactory and meets all of the requirements of the Oil and Gas Conservation Act. The Board notes that Chevron's proposal to dispose of the acid gas from the gas processing facility by injecting it into a subsurface formation is the subject of separate applications and that any approval for the gas processing facility would be given without prejudice to the formal consideration of those applications. The Board does, however, believe that the general matter of acid gas disposal is an integral part of the overall gas processing scheme. Therefore it intends to condition its plant approval to the effect that total sulphur recovery would have to be implemented if other measures for acid gas disposal were found to be unsuitable.

Having regard for urgency expressed by Chevron respecting its construction and operation schedule, the Board is issuing this Interim Decision to proceed with a conditional approval of Chevron's gas processing plant application, subject to the receipt of the necessary approval from the Minister of the Environment with respect to environmental matters. The Board will issue a further report giving its reasons for the decision in greater detail.

DATED at Calgary, Alberta, on 7 July 1988.

ENERGY RESOURCES CONSERVATION BOARD

E. J. Mink, P.Eng.
Board Member

J. P. Prince, Ph.D.
Board Member

J. R. Nichol, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

Decision D 88-9
Application 871435
Application 880727

CHEVRON CANADA RESOURCES LIMITED
ICG RESOURCES LTD.
GAS PROCESSING FACILITIES IN THE ACHESON FIELD

1 APPLICATIONS

1.1 Application 871435

Chevron Canada Resources Limited (Chevron) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct a sour gas processing plant to be located in legal subdivision 5 of section 2, township 53, range 26, west of the 4th meridian (5-2), in the Acheson area. The plant would be designed to process a maximum of 500.0 thousand cubic metres per day (500 x 10^3 m^3/d) of raw gas from which 343.3 x 10^3 m^3 of residue gas, 570.5 m^3 of ethane plus mix (C_2+), and a maximum of 1116 m^3/d of hydrogen sulphide (H_2S) (1.51 tonnes per day sulphur equivalent) would be recovered. Chevron proposed to inject the H_2S and carbon dioxide (acid gas) to an underground formation for disposal, or in conjunction with its adjacent enhanced oil operations. Therefore, under normal operating conditions, no sulphur compounds would be emitted to the atmosphere.

1.2 Application 880727

ICG Resources Ltd. (ICG) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to increase the maximum capacity of its Acheson sour gas plant located in the southwest quarter of section 2, township 53, range 26, west of the 4th meridian.

Expansion would increase the capacity of the plant by 218.0 x 10^3 m^3/d of raw gas which would result in additional product recovery of 168.3 x 10^3 m^3 of residue gas and 283.5 m^3 of natural gas liquids. The expanded plant would have a maximum capacity of 500 x 10^3 m^3/d from which 343.3 x 10^3 m^3 of residue gas and 570.5 m^3 of ethane-plus mix would be recovered. ICG proposed that a Lo-Cat sulphur recovery process would be utilized to recover a maximum of 1.51 tonnes per day (t/d) of sulphur from the 1116 m^3/d of H_2S recovered from the raw gas. Therefore, under normal operating conditions, no sulphur compounds would be emitted to the atmosphere.

2 HEARING

The applications were considered by the Board at a public hearing in Edmonton on 31 May through 2 June 1988 with F. J. Mink, P.Eng., J. P. Prince, Ph.D., and J. Nichol, P.Eng., Acting Board Member, sitting. Those who appeared at the hearing and the abbreviations used in this report are listed in the table attached.

3 PRELIMINARY MATTERS

At the commencement of the hearing, three matters were raised by counsel for the participants concerning certain procedural questions.

The first question that was raised addressed the matter of considering the applications consecutively or concurrently. Both Chevron and ICG requested that the applications be heard consecutively.

The Board staff requested that the applications be heard concurrently, or, if held consecutively, the parties agree that the evidence from both be available to the Board in determining the disposition of each application.

The second question considered by the Board concerned the relevance of two applications submitted to the Board by Chevron for approval of its proposed acid gas disposal scheme. Application 880818 was submitted to the Board for approval to dispose of acid gas in the Ostracod Formation in Chevron's well at 14-2A-53-26 W4M (14-2A). Application 880922 was submitted for a permit to construct a sour gas pipeline from Chevron's proposed 5-2 gas plant to its proposed 14-2A disposal well.

ICG maintained that Chevron's proposal to dispose of acid gas by injection into the Ostracod Formation in the 14-2A well, is an essential part of Chevron's overall processing scheme and, therefore, should be heard in conjunction with Chevron's application to construct a gas processing plant. Chevron indicated that the applications for its proposed acid gas disposal scheme had only recently been submitted to the Board and believed that it would not be appropriate to consider those applications in detail with its gas processing plant application. However, Chevron indicated that it had no objections to discussing the general matters of its acid gas disposal scheme insofar as it related to its gas processing plant application.

The third matter raised by the applicants was the question of the status of ICG's intervention against Chevron's pipeline and acid gas injection applications. ICG referred to the Board's regulations which require the proponent of a gas processing facility to address sulphur recovery and stated that Chevron did not include sulphur recovery in its revised gas

processing plant application; rather, Chevron's proposal to dispose of the acid gas was contained in separate applications. Therefore, ICG maintained that the matter of disposing of the acid gas produced at the proposed Chevron gas processing plant was an integral part of Chevron's plant application and that ICG had the right to intervene in all aspects of Chevron's gas processing scheme.

Board Rulings on Preliminary Matters

After deliberating on each of the procedural matters, the Board determined the following:

- Consecutive or Concurrent Hearings - The Board agreed to hear the two applications consecutively but with the understanding that the evidence presented with respect to both applications would be considered by the Board in making its decision whether to approve both, one, or neither of the proposed schemes.

  The Board also requested that there be a single argument from each intervener which would be presented after both applications were heard in their entirety. All participants agreed with this request.

  Ms. P. Young, a representative of the Parkland Rural Residents Association (PRRA) stated that her organization was neither in support of nor against either application and that the PRRA's intervention addressed environmental and safety concerns it had regarding the Chevron and ICG applications. Ms. Young requested that she be allowed to present her intervention to both parties after the two applications had been heard. The Board agreed to this request as well.

- The Board's Consideration of Chevron's Acid Gas Disposal Applications - The Board determined that the consideration of Application 880818 and Application 880922 would be inappropriate at this hearing as the Board's technical review of these applications was not complete at the time of the hearing. However, all parties were prepared to speak to the general matters regarding Chevron's applications for approval of its acid gas disposal scheme and its associated pipeline. The Board believed that there would be merit in considering the general matters of Chevron's proposed acid gas disposal scheme in order to identify and address the issues of any concerned parties. Furthermore, the Board also believed that addressing the issues and concerns at this time would assist it in the review of the acid gas disposal scheme at a later date. Therefore, the Board agreed that questions pertaining to the general matters of Chevron's proposed acid gas injection scheme could be raised by the interveners.

- ICG's Status as an Intervener Against Chevron's Acid Gas Disposal Application - Although separate applications must be, and were, submitted to the Board by Chevron for approval of its proposed method of disposing of acid gas by injection, the Board recognizes that the disposal of acid gas produced at the proposed Chevron gas plant is an integral part of its overall processing scheme. Given that the Board has decided not to consider Application 880818 and Application 880922, but rather to allow general questions pertaining to the proposed acid gas injection scheme, the Board will allow ICG to question and cross-examine the applicant in these matters.

4 DISPOSITION OF APPLICATION 880727

During the course of the hearing, Chevron stated that it anticipated that the chase gas phase of its miscible flood project would commence in January 1989 and that if the recovery of solvent and chase gas from the returning miscible fluids were to be maximized, then the facilities required to process these fluids had to be in operation by that date. Chevron also stated that in order to meet this time frame, it required that a decision be rendered on its application by no later than 15 June 1988.

In its closing argument, Chevron reiterated the need for an early decision to allow it to complete the construction and operation schedule associated with its project. Conversely, ICG requested that the Board defer its decision until 15 June 1988 to allow the parties sufficient time to continue their negotiations for a voluntary solution to the problem of determining the location of the additional processing capacity which is required in the Acheson area. At the close of the hearing, the Board indicated that it strongly endorsed the concept of a negotiated settlement for resolving industry conflict and requested that both parties report on the results of their continued negotiations by 15 June 1988.

On 15 June 1988, Chevron and ICG advised the Board that a tentative settlement had been reached that would result in only the Chevron gas processing facility proceeding. On 6 July 1988, the Board was formally advised that a formal agreement between the parties had been reached which would result in Chevron purchasing and salvaging the existing ICG Acheson gas processing plant, and ICG withdrawing its application to expand its facility and its intervention against Chevron's application to construct a new plant.

ICG's plant application has been deregistered; therefore, the Board does not intend to consider ICG's application, nor its intervention against Chevron's application, any further.

An interim decision report regarding the disposition of Applications 871435 and 880727 was issued on 7 July 1988. This interim decision is attached as Appendix A.

5 ISSUES

The Board considers the issues with respect to Chevron's application to be

- the need for additional processing capacity in the Acheson area, and
- sulphur recovery or acid gas disposal.

6 NEED FOR ADDITIONAL PROCESSING CAPACITY IN THE ACHESON AREA

6.1 Views of Chevron

In its application, Chevron stated that it required additional processing capacity in the Acheson area and that it would require this additional capacity to be available by no later than January 1989 in order to maximize the recovery of solvent and chase gas from its adjacent miscible flood scheme.

Chevron stated that the existing ICG gas plant does not have sufficient capacity to process the fluids from the miscible flood, nor does it have the proper processing equipment to recover an ethane-plus mix from the inlet gas stream. Chevron also believes that it is necessary to construct its own plant in the Acheson area in order to maintain flexibility in its operation of the miscible flood scheme. The applicant cited the necessity of monitoring the miscible fluids and the ability to change the liquid recovery levels to match the changing composition of the produced gas almost instantaneously as key reasons why it should have its own processing facility. In support of this, Chevron also stated that it owned over 80 per cent of the oil and gas reserves in the Acheson area and had the proprietary right to process its oil and gas in its own facility.

In addition, Chevron has identified a number of wells in the Acheson area which may contain potential reserves totalling approximately 563 x 10^6 m^3 of uphole gas. Uphole gas is natural gas which is usually found in small volumes and contained in formations at shallow depths. Chevron stated that its preliminary review indicated that the recovery of these reserves may only be marginally economic; therefore, having to pay a processing fee to a third party could result in such development

becoming uneconomic. Chevron concluded that if it was unable to construct and operate its own gas processing facility in the Acheson area, then these uphole gas reserves could remain undeveloped.

6.2 Views of the Interveners

Both N. Marano of Marnell Resources Ltd., who represented a group of eight third-party oil and gas producers in the Acheson area, and H. F. Koetsier of Leddy Exploration Ltd. stated that following Chevron's withdrawal of its gas volumes from ICG's plant in July 1987 for use in its miscible flood scheme, ICG informed the third-party area producers that it had insufficient gas to maintain operation of its plant. Marnell and the group of operators it represents stated that they had attempted to locate additional sources of raw gas that could be processed in the ICG plant. However, Marnell also stated that even if additional gas sources were found, ICG indicated to them that a drastically reduced plant inlet rate would increase substantially the unit processing charge for all gas being processed in its Acheson gas plant, rendering the conservation of solution gas produced from the third party oil batteries uneconomic.

Both Leddy and Marnell stated that they support Chevron's application and have made firm nominations for processing capacity in Chevron's proposed facility.

W. Cameron stated that the City of Edmonton (the City) had concerns about the need for a second gas processing plant in the Acheson area, in light of the West Edmonton Inquiry's recommendation that there should be no redundant gas processing facilities in this area.

The City was also concerned with the continuous flaring of solution gas in the Acheson area and therefore recognized that additional processing capacity is required. The City recognized that, because of the current existence of oil and gas development in this area, there would be no land-use conflict if Chevron's application were approved.

6.3 Views of the Board

The Board agrees with the applicants and the interveners that additional processing capacity in the Acheson area is required in order to process the solvent and the chase gas from Chevron's miscible flood scheme and that this additional capacity should be sufficient to accommodate all of the processing needs of the third-party oil and gas producers in the area as well.

The Board believes that the determination of the optimum location of this additional capacity should be based on the following considerations:

(1) plant proliferation and the potential land use impact of constructing a new facility in the Acheson area,

(2) the capability of the proposed scheme to process the solution gas produced by third-party operators in the Acheson area, and

(3) the ability of the proposed scheme to meet the operational requirements of Chevron's miscible flood project.

The Board's West Edmonton Inquiry Report, D 83-F, recommended that an expansion of the ICG gas plant would be the most desirable alternative of providing additional processing capacity in the Acheson area. However, the report also states that this recommendation was made without prejudice to applications received by the Board in future and, although the approval of Chevron's application would result in the construction of additional gas processing capacity in the West Edmonton area, the new plant would, in fact, be replacing an existing gas processing plant. The Board recognizes that the land site proposed for Chevron's plant is zoned by the County of Parkland No. 31 for industrial use and that Chevron has already obtained a development permit from the County. Furthermore, the Board notes that the proposed location currently contains the facilities for Chevron's miscible flood project and central oil battery. Therefore, in this case, the Board believes that the construction of Chevron's proposed new gas plant would have little impact on local land use.

However, the Board notes that plant proliferation was raised as an issue during the course of the hearing and indeed, notes that across the province, the issue of plant proliferation is increasingly being raised by public, industry, and government. The Board is aware that in the past 5 years, the number of gas plants in the province has increased significantly, while overall utilization of plant capacity remains at approximately 45 to 50 per cent of available capacity, on average, at a time when markets for gas have, until recently, remained essentially unchanged or, in some instances, even declined. The Board questions whether it is in the public interest to continue approving gas plants under these circumstances.

The Board is cognizant of the wishes of operators to control their own operations, take advantage of gas cost allowance provisions available in the past, and, most importantly, continue to utilize the latest, most highly efficient and economic technology. However, the Board also believes that industry should have regard for the proliferation of facilities, and ensure all options and alternatives available have been explored before deciding another facility is needed in the area under consideration.

The Board recognizes that Chevron has certain operational requirements for its miscible flood project and that it is desirable that the facilities required for the processing of the solvent used in the miscible flood be operational at the start of the chase gas phase of the project, which is anticipated to commence in January 1989. The Board notes that the majority of the third-party solution gas producers in the Acheson area have nominated processing capacity in Chevron's proposed plant. Chevron has sized its plant to accommodate the needs of these third-party producers.

Therefore, the Board believes that the required additional processing facilities are justified and should be operated by Chevron and located on the same site as its existing miscible flood and oil battery facilities.

7 SULPHUR RECOVERY OR ACID GAS DISPOSAL

7.1 Views of Chevron

In its original application dated 17 September 1987, Chevron indicated that it would flare the acid gas produced from its proposed gas processing plant. In its submission to the Board dated 15 February 1988, Chevron revised its application to include a proposal to transport its proposed plant's acid gas stream to a well located at 14-2A-53-26 W4M and inject the acid gas into the well's Ostracod Formation. Chevron agreed that the applications it submitted to the Board for approval of its scheme to dispose of acid gas in the 14-2A well were not complete and stated that if this was found to be an unsuitable proposal, then Chevron was prepared to recombine the acid gas produced at the processing plant with the residue gas stream and inject it into the D-3 A formation as part of the chase gas phase of its miscible flood project. Chevron believed that its miscible flood project approval would allow the injection of the acid gas with the chase gas into the D-3 A.

Chevron said that injection of the acid gas was a better alternative to eliminating sulphur emissions than utilizing the Lo-Cat process because the capital cost of its proposed injection scheme would be lower than the cost estimate it obtained for a Lo-Cat unit. However, if the acid gas disposal application was denied and it was determined that the injection of the acid gas with the chase gas was not approved as part of its miscible flood project, Chevron indicated that it would then consider the incorporation of a Lo-Cat unit into its gas processing scheme.

7.2 Views of the Interveners

The PRRA and the City were concerned with Chevron's initial proposal to flare acid gas if its gas processing plant was approved. The revised Chevron application, which includes the proposal to eliminate sulphur emissions by injecting the acid gas into a subsurface formation, addressed the questions that the PRRA and the City had regarding sulphur emissions, provided that the injection operations could be carried out in a technically and environmentally safe manner.

The PRRA requested assurance that if Chevron's plant application is approved, appropriate conditions will be placed on the plant owner to ensure that the plant and its associated acid gas disposal scheme would be operated in a safe and environmentally clean manner.

7.3 Views of the Board

The Board believes that any new sour gas processing facilities, approved to operate in the West Edmonton area, should incorporate methods to ensure that there are no emissions of sulphur or sulphur compounds to the atmosphere under normal operating conditions.

At this time the Board cannot comment on the specific details of Chevron's acid gas disposal scheme, as the review of the applications for this scheme are still under review. However, Chevron's general proposal to inject acid gas into either the Ostracod or D-3 A formations does not appear unreasonable. The Board also notes Chevron's willingness to utilize a Lo-Cat unit in its processing scheme should its applications to inject the acid gas be denied.

8 DECISION

Having considered the technical, safety, and environmental aspects of Chevron's application to construct a gas processing facility in the Acheson area, the Board believes approval of the subject facility is in the public interest. It is satisfied that the proposed gas plant will meet the operational requirements of Chevron's enhanced oil operations and has been adequately designed to accommodate the solution gas produced by third-party operators in this area.

In its interim decision report dated 7 July 1988, the Board granted its approval of Chevron's application, subject to the receipt of the necessary approval from the Minister of Environment with respect to

environmental matters. The Board approval stipulates that under normal operating conditions, there will be no emission of sulphur or sulphur compounds to the atmosphere.

DATED at Calgary, Alberta, on 11 August 1988.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Board Member

J. P. Prince

J. P. Prince, Ph.D.
Board Member

J.R. Nichol

J. Nichol, P.Eng.
Acting Board Member

Mr. Mink was unavailable to sign the Decision Report, but is in agreement with the decision.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Chevron Canada Resources Limited (Chevron) B. K. O'Ferrall	W. H. Armstrong, P.Eng. S. Hutchison, P.Eng. C. Bowen, P.Eng. M. Philpott, P.Eng.
ICG Resources Ltd. (ICG) J. B. Ballem T. Hughes H. R. Hansford	P. Krenkel, P.Eng. R. Bailey, P.Eng. R. Clare, P.Eng., of Colt Engineering Ltd.
Marnell Resources Ltd. (Marnell) N. Marano	N. Marano M. Choran, P.Eng.
Leddy Exploration Limited (Leddy) H. F. Koetsier, P.Eng.	H. F. Koetsier, P.Eng.
City of Edmonton (the City) W. Cameron	W. Cameron
Parkland Rural Residents Association (PRRA) P. Young L. Gadalah	P. Young L. Gadalah
Government of Alberta S. Dobko, P.Eng. C. S. Liu, P.Eng.	
Energy Resources Conservation Board staff C.J.C. Page E. P. Moeller, R.E.T. C. L. McAdie, C.E.T.	

Alberta Environment stated that it was appearing at the hearing for the purpose of cross-examination only.

Karl Kocan and Trevor Morrison submitted interventions but did not appear at the hearing.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

CHEVRON CANADA RESOURCES LIMITED	Application 871435
ICG RESOURCES LTD.	Application 880727
GAS PROCESSING FACILITIES IN THE ACHESON FIELD	Interim Decision D 88-9

At a public hearing held in Edmonton, on 31 May through 2 June 1988, the Energy Resources Conservation Board (ERCB) considered an application by Chevron Canada Resources Limited (Chevron) to construct a gas processing plant designed to process a maximum of 500.0 thousand cubic metres per day (10^3 m^3/d) of raw gas and located on Chevron property adjacent to the existing ICG gas plant. At the same hearing the Board also considered an application from ICG Resources Ltd. (ICG) to expand its existing gas plant in section 2, township 53, range 26, west of the 4th meridian, to the same throughput level as the proposed Chevron facility. Both gas processing facilities were to be designed to produce the same volume of residue gas and ethane-plus mix from essentially the same raw gas sources.

Under normal operating conditions, there would be no emission of sulphur or sulphur compounds to the atmosphere from either of the proposed gas processing facilities. Chevron proposed to inject the 1116 m^3/d of hydrogen sulphide (1.51 tonnes per day (t/d) sulphur equivalent), recovered from the raw gas stream, to an underground formation either for disposal or in conjunction with its enhanced oil recovery operations. ICG proposed to recover the same volume of sulphur through the operation of a Lo-Cat sulphur recovery system.

In its closing argument Chevron reiterated the need for an early decision to allow it to complete the tight construction and operation schedule associated with this project. ICG conversely requested the Board to defer its decision until 15 June 1988 to allow the parties to continue negotiating a voluntary solution to this problem. At the close of the hearing the Board strongly endorsed the concept of negotiated settlement to this conflict and requested the parties to report on the results of their negotiations by 15 June 1988.

On 15 June 1988, Chevron and ICG advised the Board that a tentative settlement had been reached that would result in only the Chevron gas processing facility proceeding. On 6 July 1988 the Board was formally advised that formal agreement was reached between the parties for Chevron to purchase and salvage the ICG facility and that ICG had withdrawn its application to build an expanded plant.

The Board is satisfied that there is a need for additional gas processing capacity in the Acheson area and that only one facility is required. As the parties have reached an agreement respecting the construction of only the Chevron facility, the Board is prepared to approve that facility as described in Chevron's application.

The Board is satisfied that the Chevron proposal respecting the gas processing facility is technically and environmentally satisfactory and meets all of the requirements of the Oil and Gas Conservation Act. The Board notes that Chevron's proposal to dispose of the acid gas from the gas processing facility by injecting it into a subsurface formation is the subject of separate applications and that any approval for the gas processing facility would be given without prejudice to the formal consideration of those applications. The Board does, however, believe that the general matter of acid gas disposal is an integral part of the overall gas processing scheme. Therefore it intends to condition its plant approval to the effect that total sulphur recovery would have to be implemented if other measures for acid gas disposal were found to be unsuitable.

Having regard for urgency expressed by Chevron respecting its construction and operation schedule, the Board is issuing this Interim Decision to proceed with a conditional approval of Chevron's gas processing plant application, subject to the receipt of the necessary approval from the Minister of the Environment with respect to environmental matters. The Board will issue a further report giving its reasons for the decision in greater detail.

DATED at Calgary, Alberta, on 7 July 1988.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Board Member

J. P. Prince, Ph.D.
Board Member

J. R. Nichol

J. R. Nichol, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

C-H SYNFUELS LTD.
APPLICATION TO CONSTRUCT
AN OIL SANDS DREDGING PROJECT

Decision D 88-10
Application 870612

1 INTRODUCTION

1.1 Application

C-H Synfuels Ltd. (C-H) applied to the Energy Resources Conservation Board (Board or ERCB), pursuant to sections 10 and 11 of the Oil Sands Conservation Act, for approval to construct an oil sands dredging project in section 8, township 89, range 9, west of the 4th meridian (Figures 1 and 2).

The scheme would involve dredging of a cutoff meander in the Horse River some 900 metres from the Fort McMurray subdivision of Abasand Heights. Extraction of the dredged bitumen would take place on a floating modular process barge employing a modified version of the Clark Hot Water Process. The resulting bitumen would be stored in tanks, allowed to cool and solidify, then transported, via truck and barge, to either Suncor or the City of Fort McMurray. Tailings treatment would employ a novel method combining the sand and sludge, thus eliminating the need for a large conventional tailings pond.

The applicant has requested an approval period of 5 years.

2 BACKGROUND

The application was received by the Board in May 1987. It was reviewed internally and by government departments. Following the review, further information was requested from the applicant.

The Board considered the application complete in February of 1988. However, because many questions that had been raised by concerned Fort McMurray residents at a public meeting in December of 1987 remained unanswered, the Board decided to issue a Notice for Objection. C-H held a second public meeting in an attempt to answer these questions. However, the Board still received 13 objections, including one with a petition of 53 names.

3 HEARING

The application was considered at a public hearing on 9 and 10 May 1988 in Fort McMurray. Sitting were N. A. Strom, P.Eng., J. P. Prince, Ph.D., and T. F. Homeniuk, P.Eng. (Acting Board Member). Table 1 is a list of the participants at the hearing.

R. 9 W.4 M.

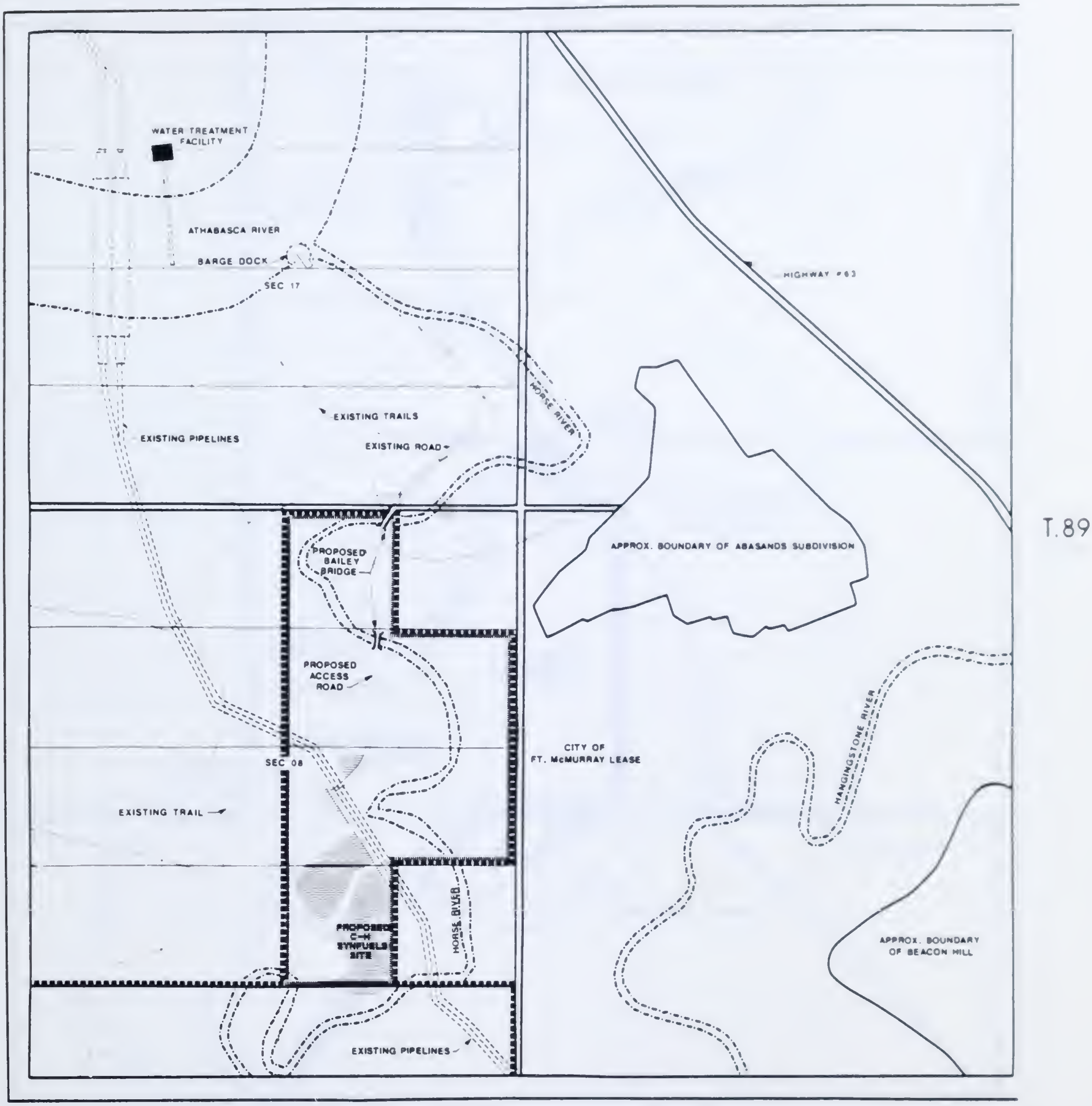


FIGURE 1: C-H SYNFUELS LTD.
GENERAL AREA PLAN

R.9 W. 4 M.

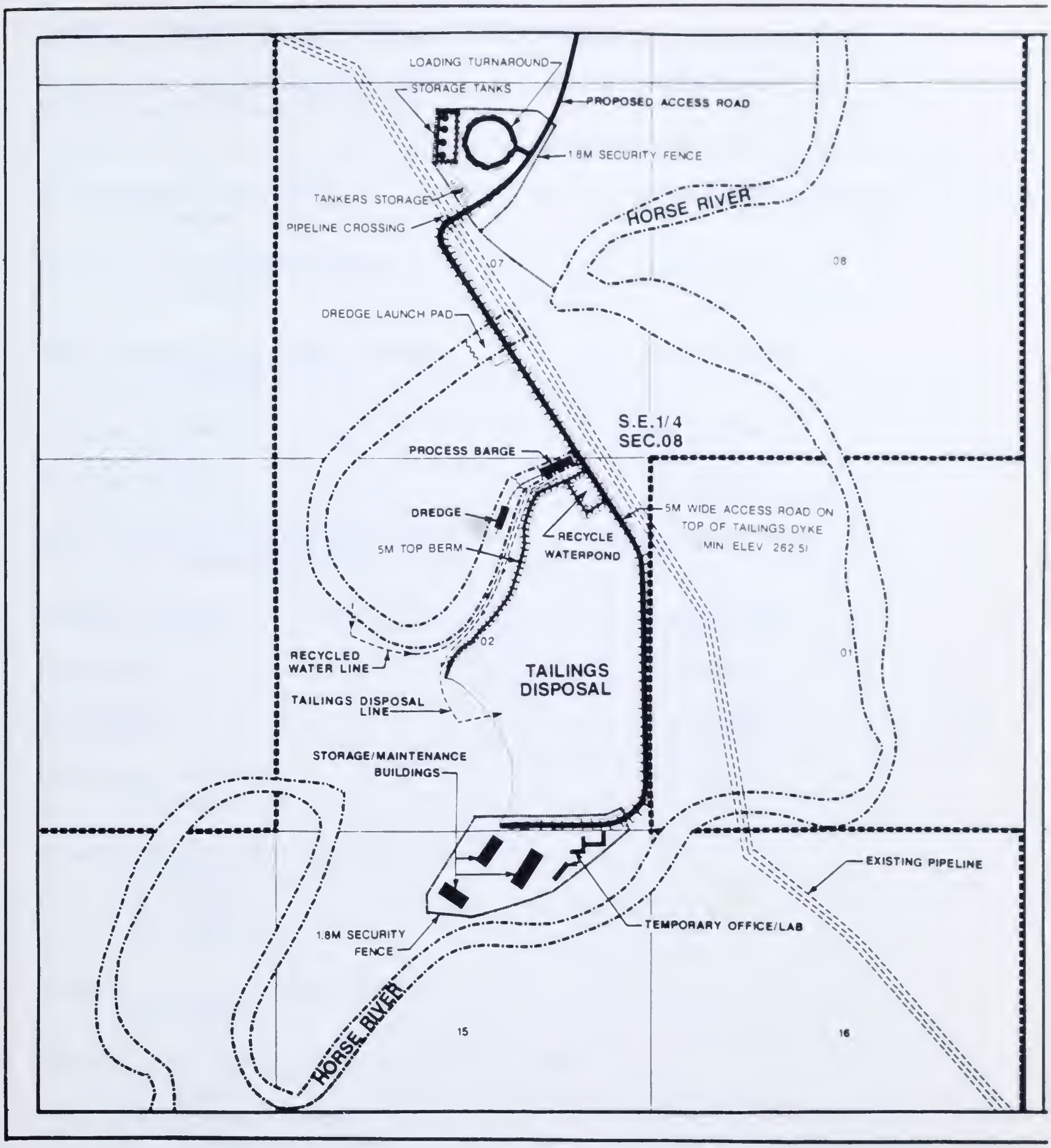


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FIGURE 2 : C-H SYNFUELS LTD.

PROPOSED SITE PLAN

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
C-H Synfuels Ltd. (C-H) W. Major, Q.C.	S. J. Lane, P.Eng.
City of Fort McMurray (City) S. Clarke	S. Clarke
David Sliziak and Wendy Priebe D. Sliziak	D. Sliziak
Valance Bussey	V. Bussey
Glenda Pilger	G. Pilger
Lyse Desormeaux and Daniel Gauthier L. Desormeaux	L. Desormeaux
George Skulsky	G. Skulsky
Ron Cooper	R. Cooper
Jim Rogers	J. Rogers
Karen and Rick Foy K. Foy	K. Foy
Alberta Environment (A.Env.) staff B. Stone L. Brocke I. Mackenzie	
Alberta Forest Services staff H. Walker	
Energy Resources Conservation Board staff M. Bruni B. Prasad, P.Eng. B. Gartshore, P.Eng. R. St. Amour	

4 ISSUES

The Board considers that there are three main issues. These are:

(a) potential benefits in improved technology,

(b) criteria used to select the site, and

(c) effects of the project on the environment and the community.

5 POTENTIAL BENEFITS IN IMPROVED TECHNOLOGY

C-H proposed to use a small-scale dredge to evaluate the feasibility of mining the oil sands by dredging. Although dredging is common in other mining operations, it is not currently used in the oil sands industry. C-H stated that the bitumen would be extracted from the oil sands in a fully enclosed process barge. The extraction method to be used would be a modification of the hot water process using mechanical energy in the form of augers, as well as hot water. Chemicals would not be used. C-H was not prepared to divulge details of its extraction method since that information is proprietary and of competitive value.

C-H proposed to add lime and a non-toxic polyacrylamide polymer to the tailings stream. This would cause the fines to attach to the sand eliminating the need for a sludge pond. C-H claimed that the resulting tailings could withstand traffic within a week and thus serve as a good base for reclamation. In laboratory tests, C-H found that jackpines and slender wheatgrass adapted well to the material.

The Board believes that recovery of oil sands by dredging could provide large advantages over existing methods and therefore warrants testing. As well, the proposal by C-H to field test an integrated system for dredge-mining, extraction and tailings treatment presents the possibility for an overall improved system for mining and tailings management.

As is the case with other experimental oil sands schemes, the sponsor wishes to protect proprietary technology and therefore is only prepared to reveal very limited information. The Board's view is that as long as the operation is technically and environmentally safe, it would endorse proceeding with the tests. While no serious risks appear to exist, scrutiny of construction and operation by regulatory personnel will be necessary to confirm that such is the situation.

6 CRITERIA USED TO SELECT THE SITE

C-H stated that the site chosen is one that satisfied a series of criteria identified by C-H as necessary (musts) and desirable (wants). These are as follows:

"Musts"

- the site must have exposed oil sands or oil sands that could be readily exposed in a configuration under water or that could be flooded,

- the site must not be an integral part of a river or lake where the dredging activity would be detrimental to the environment, and

- the site must be accessible from the surface.

"Wants"

- the ideal configuration would be a cutoff meander with less than 8 metres (26 feet) of overburden and oil sands below the water table ideally with a minimum proportion of overburden,

- the site should have sufficient geological data available to properly assess its suitability for the proposed activity,

- the geological features should be positive; namely, a reasonable grade of oil sands, minimal or no indurated sandstone, and, ideally, some low-grade oil sands present as well, and

- it should be possible to provide utilities such as gas and electricity to the site.

C-H pointed out that the geological situation and the physiographical setting was virtually ideal for the kind of test it wishes to conduct. Also, C-H stated that other possible sites, such as the Shell test pit, had been discussed but an agreement could not be reached with the leaseholders.

The Board agrees that the geology and physiography of the selected site provide advantages for the kind of small field test planned by C-H. However, site access is not particularly ideal as it would entail installing a barge dock on the Athabasca River plus construction of a heavy-equipment access road along the narrow Horse River valley. The Board believes, on balance, that a more readily accessible place, such as a test pit on one of the readily accessible, mineable oil sands leases, would be as satisfactory from a geological point of view without introducing the complications for access apparent in the applied-for site. In spite of those reservations, however, the Board would not deny use of the site if environmental problems and neighbourhood concerns could be satisfactorily accommodated.

7 EFFECTS OF THE PROJECT ON THE ENVIRONMENT AND THE COMMUNITY

The Board considers that the project may affect the environment and the community as follows:

(a) its proximity to Abasand Heights,

(b) the need for upgraded site access,

(c) disturbing a natural area,

(d) possible water contamination,

(e) safety and security of the residents,

(f) geotechnical matters,

(g) reclamation activities,

(h) impact on property values, and

(i) potential establishment of a Community Advisory Committee.

7.1 Proximity to Abasand Heights

The majority of the interveners stated that their main concern with the project was that it is simply too close to a residential area. One intervener suggested that if the project site were located farther away from Abasand Heights, there would not have been any interventions.

In response to concerns that the project could affect the sleeping and recreational habits of the residents of Abasand Heights, C-H stated that, because sound travels in a straight line and there are no residences in Abasand Heights that have a direct line of site to the project, the residents would not be able to hear the operation. C-H compared the proposed project to Highway 63 noise which, it stated, is noisier than the proposed project yet is not heard by residents of Abasand Heights. C-H also stated that a normal conversation would be possible while standing on the deck of the dredge and that people walking in the valley may hear some noise but that it would not be excessive.

Regarding noise levels from the site clearing equipment, C-H stated that work had been done previously by others in the same immediate area, and there had been no complaints by the residents. C-H further stated that it would be prepared to operate within the City nuisance by-law guidelines. However, it requested leniency on this if it were found that, in fact, noise levels were not disturbing anyone.

Regarding potential odour and hydrogen sulphide (H_2S) problems, C-H noted that the process would not be using naphtha. Therefore, the project would not give off any odours that are not currently natural to the area. As well, C-H proposed to use a skimmer system to recover any bitumen surfacing in the dredging area. C-H stated that all the bitumen processing vessels would be fully enclosed and would operate at low temperatures so that venting of gases would not be necessary. C-H produced a chart, developed following experiments at the Alberta Research Council, showing that, at the proposed operating temperatures of $70^{o}C$, H_2S emission from the oil sands would be less than 0.01×10^{-8} mole/hr - kg, a level below the odour threshold level.

The Board believes that the size of the facilities and test site can be compared to that of an industrial operation such as, for example, a gravel pit where the degree of adverse impacts can be qualitatively defined in terms of noise, odours, and visual or nuisance effects. The Board is inclined to agree with C-H that noise levels would not likely be noticeable in the Abasand Heights subdivision. Similarly, visual impacts should be negligible considering that the site can only be viewed by walking a considerable distance along the inter-valley ridge. The matter of odours is less well defined because little information was revealed regarding the extraction method. For instance, the notion of transporting bitumen by truck seems to present some possibility of odours emanating from heated bitumen.

The Board concludes that, although there seems little likelihood of serious impacts, should any occur, C-H would bear the risk of correcting them to the satisfaction of the City and nearby residents.

7.2 Site Access

The main transportation route along the Horse River valley would be as shown on Figure 1. Residents expressed concern that trucks travelling to and from the project area would present a danger to youngsters from Abasand Heights who frequent the valley, often using "ATV trikes". Interveners also expressed concern about increased vehicular traffic going through Abasand Heights to get to the project site.

C-H stated that its preferred equipment access route to the site would be by barge on the Clearwater and Athabasca Rivers from the city of Fort McMurray to a barge loading dock located at the mouth of the Horse River. The equipment would then be trucked to the site on upgraded existing trails and two bridges that would be installed across the Horse River.

C-H personnel access to the site, if agreeable to the City, would be by an existing roadway to the former Abasand site, then proceeding on the valley road to the proposed operating site. C-H further stated that

construction of an improved road to permit small vehicle access from Abasand Heights to the Horse River valley would provide long-term advantages to local residents for use of the valley as a recreational area.

The Board believes that the issue of children and trucks on the valley transportation road is a serious one. Should the project proceed, the Board would expect C-H to conduct a thorough orientation program for all employees driving vehicles on the route, with particular emphasis on safety and awareness.

7.3 Natural Area

The interveners described the proposed project site as a beautiful natural area, stating that they enjoyed walking to an accessible area, referred to as the saddle, to relax, watch the sunsets over the proposed project area, and enjoy the scenery. Some interveners described using all-terrain vehicles over the old steep access road to the river valley. Others conceded that the project area in its natural state is not easily accessible and is somewhat of a swamp.

C-H stated that the project would only be seen by those who walk in the area referred to as the saddle and, even then, it may or may not be noticeable because of the surrounding trees. C-H also suggested that, by allowing the project to go ahead, the area would ultimately be more attractive because a swimming lake with good access to it would remain upon completion of the project.

In response to concerns about effects of the project on wildlife, C-H stated that the project would operate only during summer months and therefore should have no impact on migratory patterns. C-H agreed that the operating noise in the immediate area of the project may keep wildlife, including birds, away.

The Board agrees that access to the Horse River valley is difficult, especially during the summer months. However, it believes that an improved small vehicle road from Abasand Heights to the river valley would overcome that problem. Such a road would also provide local residents with access to the valley.

The Board is satisfied that the all-weather road and bridges proposed by C-H to transport equipment to and bitumen from the site are acceptable. It is also satisfied that the route along the lower stretch of the Horse River valley is suitable. However, as indicated earlier in the report, C-H would be expected to have regard for the safety of local residents and their youngsters who visit the area.

The Board is also satisfied that the project would not affect the use and enjoyment of the general area by local residents for recreational purposes in the state currently used.

7.4 Water Contamination

In response to concerns about the project causing contamination of the City's water supply, C-H stated that the potential for escape of undesirable materials into the rivers would be minimal because there would be no discharge of materials into the Horse River, containment booms would be located around the dredge and the barge loading dock, and an armored berm would be constructed around the tailing and dredging areas to a height above the 100-year flood level. C-H also noted that the water intake to the City's water treatment plant is upstream from the mouth of the Horse River, thereby ensuring there would be no contamination. C-H also stated that, although the tailings process does involve lime and polyacrylamide polymer, the berm containing the tailings sand would be relatively impermeable such that these would not escape into the water system.

Regarding the transportation of bitumen, C-H stated that, because the bitumen would be transported in its cold state, it would not flow. Therefore, it is likely that if a spill did occur, the bitumen would behave as a discrete object and could easily be recovered.

The Board accepts that because of the relatively small size of the project and the measures proposed by C-H, the risk of water contamination in either the Horse or Athabasca River should be negligible. Additionally, the operation would be subject to stringent measures imposed by A.Env. under the Clean Water Act. In the event that contamination did occur, C-H would be required to take corrective measures, including removal of contaminated sources.

7.5 Site Safety and Security

The City stated that it would respond to emergencies at the project site. It implied that, as part of the agreement with C-H for use of the land, it would require a sum of money in order to provide that service.

Regarding concerns raised about fires on the site that could potentially spread into Abasand Heights, C-H stated that the City would be responsible for fire-fighting activities in the area. C-H would upgrade any access roads required to accommodate emergency response vehicles. C-H stated that its on-site fire-fighting equipment would be compatible with that of the City and that it would operate in accordance with the Alberta fire code.

The Board believes that C-H's willingness to upgrade the site access and to have emergency and fire-fighting equipment compatible with that of the City would ensure that emergencies would be handled quickly and efficiently.

In response to concerns for the safety of children playing in the area, C-H agreed that the area around the dredging pond and the tailings area should be fenced. C-H further stated that it would have a security person on site at all times, even when the plant is not operating.

The Board believes that, if the project were approved, it would be in the interests of both C-H and the public to classify the entire project area, exclusive of the access roads, as a restricted area and fence it as shown on Figure 2. Access to the site would be restricted to regulatory personnel and people authorized by C-H. The Board also believes that a security person should be on site at all times during operation, and that daily inspections should be made of the entire site when the project is not in operation.

7.6 Geotechnical Matters

In response to concerns about the site berm breaking or cracking, C-H stated that it would be prepared to monitor the berm for cracking and leaking on an on-going basis, even when the project is not in operation. C-H further stated that the berm would serve three functions: protection of the existing pipelines during dredging operations; road access to the site buildings; and containment dike for the tailings sand. C-H stated that the berm would be constructed by compacting oil sands to a permeability of 10^{-5} centimetres per second. This would prevent the seepage of materials into the Horse River. The dike would be armored with rip-rap and/or geotextiles to protect the rest of the site in the event of flooding of the Horse River.

In response to concerns regarding slumping of the river cutback or highwall, C-H indicated that it would avoid mining the channel near the existing highwall.

The Board believes that the berm can be constructed such that it would not become unstable. However, because the method of construction is referred to by C-H only as compacting of oil sands, the Board would require that C-H submit detailed plans of the berm prior to commencing construction of the berm. The Board would also require regular monitoring of the berm, using well-established geotechnical monitoring devices.

In regard to the natural river highwall stability, the Board would require that C-H provide the Board with plans showing the final pit walls in the dredging area, including an evaluation of the plans by a geotechnical engineer prior to commencing dredging activity.

7.7 Reclamation

The City stated that it had requested and obtained permission from A.Env. to be represented on the Development and Reclamation (D&R)

Review Committee when reclamation of the site is discussed. In this way, the City would have input into reclamation plans for the area.

Several of the interveners were concerned that C-H might become insolvent and abandon the site. Some type of assurance was requested from C-H that the area would not be abandoned prior to cleaning up the site. In particular, the City requested that, if the amount of the reclamation bond was not sufficient, then C-H's insurance policy should be made to include provisions to cover any shortfall to reclamation costs.

C-H stated that one of the purposes of the project was to prove a new tailings treatment process which would have a positive effect on reclamation. The proposed tailings treatment process would eliminate sludge by bonding the fines together with the sand by the addition of lime. This allows the material to settle much more quickly, thus significantly reducing the need for a large pond. The resulting material would be trafficable within a week and, by the addition of peat moss, the area would be ready for planting slender wheatgrass and jackpines.

Although C-H has not submitted a D&R plan to A.Env., conceptual reclamation plans are in progres and C-H proposed to leave behind a lake with contoured sandy beaches. The lake water would be detoxified and made acceptable for swimming using a method known as ozonation. C-H stated that it did not expect the City to absorb any of the capital costs involved in constructing the lake. However, the City would likely have to spend money on an annual basis to operate the lake once C-H left the area.

The City stated that it has no interest in annexing or developing the area in the foreseeable future and that it is unlikely that the City would appropriate funds to pay the operating costs of a "swimming pool" outside the city limits.

C-H recognized that the City would want to be involved in the reclamation plans as it owns the surface rights to the area. Therefore, any reclamation plans must meet with City approval. C-H also stated that the reclamation plan could be discussed at Community Advisory Committee meetings which would allow the Abasand Heights residents to have input into reclamation plans for the area. C-H stated that, in the worst situation, the area could be returned to the state it currently is in. C-H stated that it would post a bond with A.Env. such that, if for some reason it were to become insolvent, the bond would be cashed by A.Env. and used to reclaim the land.

The Board understands that the final land use, including the construction and operation of the lake, would be jointly decided by the City and Improvement District #18. A.Env., through the D&R process, would ensure that reclamation would be suitable to accommodate

final land use plans. Citizen advice on the matter could be provided by a community advisory committee if one is put in place. On the evidence adduced, the Board doubts that a recreational lake would be developed and maintained. However, the Board heard no evidence to suggest that the area could not be reclaimed to a condition as good as that which presently exists.

7.8 Property Values

In response to concerns raised about the negative impact of the project on the property values in Abasand Heights, C-H stated that there would be no impact during the operating phase because there would be no noticeable noises or odours in Abasand Heights. C-H further stated that, in the long term, property values would increase because there would be upgraded access to an area that is currently not accessible and the area would be recreationally attractive, which it currently is not.

In Section 7.1 of this report, the Board stated that it believes noises and odours would not be noticeable to the residents of Abasand Heights. For this reason, the Board agrees that the project should have no negative impacts on the property values during the life of the project. The Board further believes that the creation of a recreational area and small vehicle access to and along the Horse River valley could impact favourably on property values.

7.9 Community Advisory Committee

The interveners supported the establishment of a community advisory committee in order to be kept informed of C-H's plans. Some of the interveners stated that they would be willing to be a member of the committee. One intervener stated that he would like to be involved in monitoring the river for pollution, fire hazards, dumping of garbage, and resulting lake.

C-H openly supported the establishment of a community advisory committee, believing that membership in the community advisory committtee should include representatives of the City, the ERCB, and the Abasand Heights community. C-H agreed to the ERCB formalizing the community advisory committee process and suggested that the City could serve in some sort of mediatory capacity in the event of disagreements between C-H and other members.

The Board is of the view that a community advisory committee is a good method of providing a continuing dialogue between the community and C-H. However, the Board sees a community advisory committee as a voluntary organization and, therefore, would not proceed with any involvement unless specifically requested to do so by either C-H or the residents of Abasand Heights.

8 SUMMARY AND CONCLUSIONS

The Board concludes that there is a continuing need to encourage new technological innovations in the oil sands industry. The C-H application would simultaneously test the feasibility of (a) oil sands dredge-mining, (b) barge-mounted extraction of bitumen without the use of chemical additives, and (c) treatment of tailings to achieve rapid reclamation. Though little information is available to examine the technical merit of this proposed experimental operation, the Board sees no good reason not to endorse the field demonstration proposed by C-H, provided that technical safety and environmental integrity can be attained.

Regarding the proposed site for the project, the Board believes that there are other sites within the mineable oil sands boundaries which would probably satisfy the basic objectives of the project. There would have been few, if any, interventions had the site been located some farther distance from the city of Fort McMurray. However, the Board recognizes that C-H was unable to obtain access to other sites. On balance, the Board considers the site to be acceptable provided that suitable security and other safety measures are in place.

With reference to the potential effects of the project on the environment, the Board believes that factors such as noise and odours are not likely to be a problem. As well, surface water bodies, including the Horse and Athabasca Rivers and the resulting tailings "lake", would be subject to monitoring and protection measures administered by A.Env. under the Clean Water Act.

Regarding the implementation of a community advisory committee, the Board concludes that such a committee could be mutually beneficial to the City, the residents of Abasand Heights, and C-H. However, the Board would not participate in such a committee unless requested to do so.

9 DECISION

Having regard for its findings and its responsibility under the Oil Sands Conservation Act, the Board is prepared, subject to the approvals of the Minister of the Environment and the Minister of Forestry, Lands and Wildlife, to grant the application and authorize it in the manner shown in the attached draft Approval No. 5704.

DATED at Calgary, Alberta, on 24 June 1988.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

*J. P. Prince, Ph.D.
Board Member

T. F. Homeniuk, P.Eng.
Acting Board Member

* Dr. Prince reviewed the draft Decision Report and agreed with it. However, he was unavailable to sign the report once it was prepared for issue.

THE PROVINCE OF ALBERTA

OIL SANDS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of an experimental scheme of C-H Synfuels Ltd. for the recovery of crude bitumen from the Athabasca-Wabiscaw-McMurray oil sands deposit in the Fort McMurray Area

APPROVAL NO. 5704

WHEREAS the Energy Resources Conservation Board is prepared to grant an application by C-H Synfuels Ltd., subject to the terms and conditions herein contained, and the Minister of Environment has given his approval, hereto attached, insofar as the application affects matters of the environment, and the Minister of Forestry, Lands and Wildlife has given his approval, hereto attached, insofar as the application affects land and resources that are the property of the Crown in right of Alberta.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Oil Sands Conservation Act, being chapter O-5.5 of the Statutes of Alberta, 1983, hereby orders as follows:

1. The experimental scheme of C-H Synfuels Ltd. (hereinafter called "the Operator") for the recovery of crude bitumen from the area shown outlined on the attachment hereto, marked Appendix A to this approval, as such experimental scheme is described in Application No. 870612 dated 4 May 1987 and addenda thereto dated 27 August 1987, 15 February 1988 and 22 February 1988, is approved, subject to the Oil Sands Conservation Regulations and the terms and conditions herein contained.

2. The Operator shall commence construction of the facility on or before 1 July 1989 unless, upon application by the Operator, a later date is approved by the Board.

3. The Operator shall supply to the Board, for its approval, detailed plans on the method of construction of the site berm, including material types to be used, not less than 60 days, or such other time as specified by the Board, prior to commencement of construction of the berm.

4. The Operator shall provide detailed plans for site security to the Board, for its approval, prior to commencement of any on-site construction activity.

5. The Operator shall supply to the Board, for its approval,

(a) plans showing the final mining limits, and

(b) a geotechnical evaluation of the plans conducted by a geotechnical engineer regarding the impact on the stability of the highwall and the operating pipelines adjacent to the site

90 days, or such other time as specified by the Board, prior to commencing mining operations.

6. (1) The Operator shall devise codes of practice relating to public safety, including potential use of the site access roads by youngsters, and such other aspects as are identified from time to time.

(2) The Operator shall enforce the codes of practice outlined in subclause (1).

7. The Operator, in accordance with section 21 of the Pipeline Regulations, shall erect temporary fencing of the existing pipeline rights of way to limit access during the construction of the site berm.

8. The Operator, not less than 60 days, or such other time as specified by the Board, prior to producing bitumen, shall supply to the Board, for its approval, contingency plans for handling bitumen spills.

9. The Operator shall store in tanks, until sold or disposed of in a manner approved by the Board, all liquid hydrocarbons recovered from the operation of this scheme and not usefully consumed in the operation or in works or installations used in connection with the scheme.

10. The Operator shall dispose of all excavated material in a safe and environmentally acceptable manner satisfactory to the Board.

11. The Operator shall endeavour to conduct operations in such a way that there are no adverse environmental effects on the site, transportation access or nearby residential communities.

12. Data filed pursuant to clause 13 of this approval will be released on 30 June 2003 unless, upon application by the Operator or if other circumstances so warrant, a later date is approved by the Board.

13. The Operator shall

(a) file progress reports with the Board for each six-month period of operation commencing with the period 30 June 1988 to 31 December 1988,

(b) file the progress reports required by subclause (a) within 60 days of the expiration of each six-month period or within 120 days of the termination or continuous suspension of experimentation, whichever shall occur first, and

(c) set out in the progress reports required by subclause (a)

(i) a description of construction progress,

(ii) a chronological report of all activities and operations conducted, and

(iii) the results of any measurements or observations which are pertinent to the interpretation of the experimental operations.

14. This approval, insofar as it pertains to matters of the environment, is subject to the approval of the Minister of the Environment, hereto attached as Appendix B to this approval, and insofar as it pertains to matters that affect land and resources that are the property of the Crown in right of Alberta, is subject to the approval of the Minister of Forestry, Lands and Wildlife, hereto attached as Appendix C to this approval, and to the terms and conditions therein contained.

15. (1) The Board may,

(a) upon its own motion, or

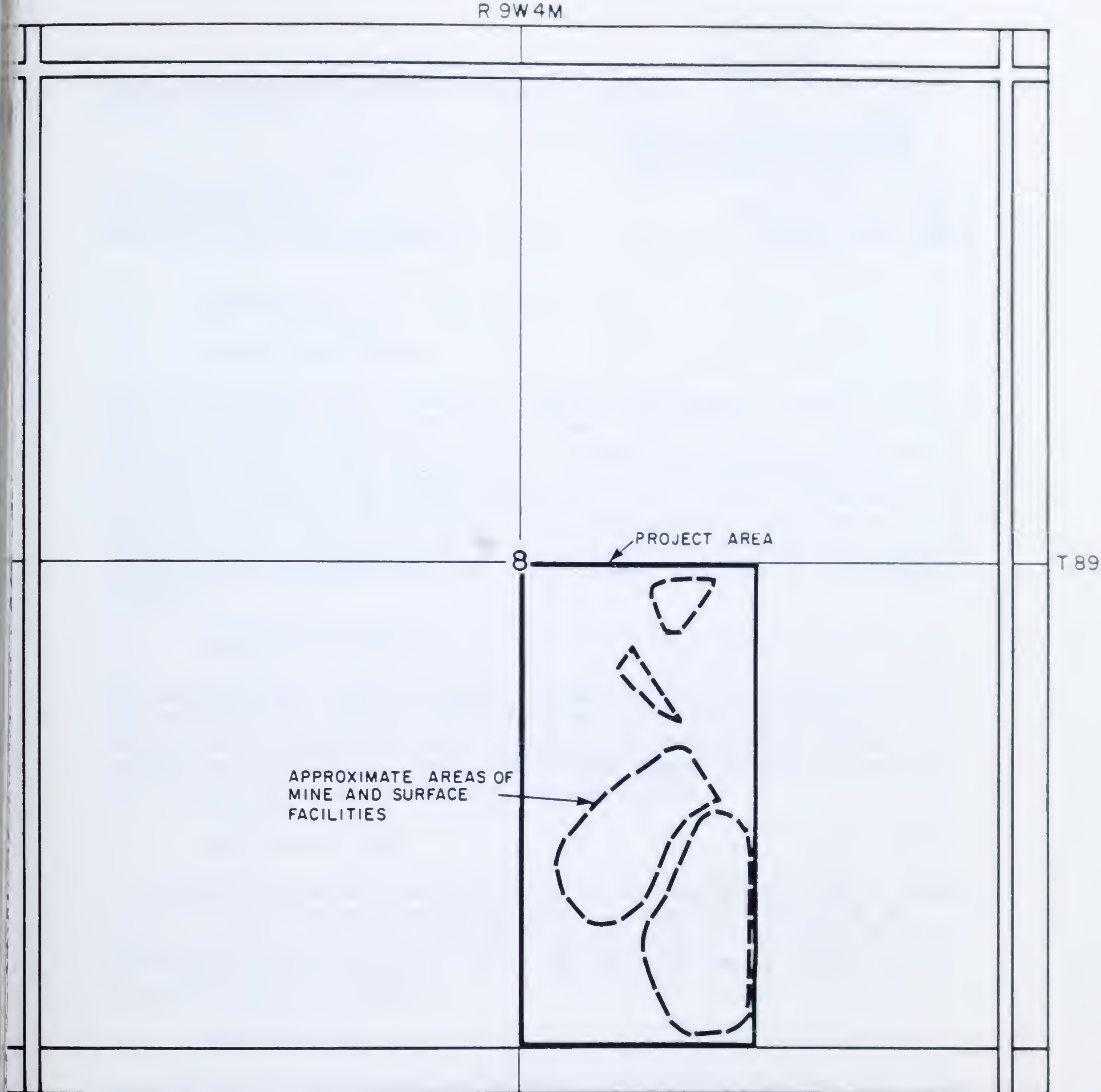
(b) upon the application of an interested person,

rescind or amend this approval at any time.

(2) This approval expires on 30 June 1993 unless rescinded before that date pursuant to subclause (1).

MADE at the City of Calgary, in the Province of Alberta, this

MEMBER OF THE
ENERGY RESOURCES CONSERVATION BOARD



FORT McMURRAY AREA
C-H SYNFUELS LTD. DREDGING PROJECT
APPENDIX A TO APPROVAL NO. 5704

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CIMARRON PETROLEUM LTD.
ICG RESOURCES LTD.
APPLICATION FOR WELL LICENCES

Decision D 88-11
Applications 880035, 880036, and 880037

1 INTRODUCTION

1.1 Application 880035

Cimarron Petroleum Ltd. (Cimarron) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations (the Regulations), for a licence to drill a well from a surface location in legal subdivision 13 of section 15, township 26, range 1, west of the 5th meridian, to a bottom-hole location in legal subdivision 16 of section 16, township 26, range 1, west of the 5th meridian. The proposed well would be known as CIMARRON ET AL CROSS 16-16-26-1 (16 of 16) and would be for the purpose of obtaining production from the Elkton Member (Elkton) of the Rundle Formation.

1.2 Application 880036

ICG Resources Ltd. (ICG) applied, pursuant to section 2.020 of the Regulations, for a licence to drill a well in legal subdivision 6 of section 10, township 26, range 1, west of the 5th meridian. The proposed well would be known as ICGR OPINAC CROSS 6-10-26-1 (6 of 10) and would be to obtain production from the Elkton.

1.3 Application 880037

ICG applied, pursuant to section 2.020 of the Regulations, for a licence to drill a well in legal subdivision 14 of section 10, township 26, range 1, west of the 5th meridian. The proposed well would be known as ICGR OPINAC CROSS 14-10-26-1 (14 of 10) and would be to obtain production from the Elkton.

1.4 Interventions

Interventions opposing the applications were received by the Board from a number of landowners and residents in the vicinity of the proposed wells. These persons did not generally take issue with the technical aspects of the applications but had numerous concerns regarding safety, environmental impact, noise, odours, effects of sour gas, lifestyle impact, and property devaluation and compensation.

The City of Calgary (the City) submitted that urban development should take precedence over energy development in this area. The City requested that the Board limit operations at the wells to 15 years, after which the wells should be considered for abandonment to allow urban development.

The Calgary Regional Planning Commission (the Planning Commission) filed a submission supporting rapid depletion of any hydrocarbon that might be found, prior to any serious conflict between sour gas and land use development occurring.

Those who appeared to speak to their submissions are identified in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Cimarron Petroleum Ltd. (Cimarron) and ICG Resources Ltd. (ICG)[1] R. A. Neufeld	D. S. Belczewski, P.Eng. K. R. Bissett K. M. Harrington, P.Geol. D. H. Ibach, P.Geol. P. Krenkel, P.Eng. D. M. Leahey, Ph.D. R. W. Pawliw, P.Eng. W. T. Wilson, P.Eng.
The Niedzwiecki Family (Mrs. Niedzwiecki) S. E. Niedzwiecki	S. E. Niedzwiecki
C. B. Stickle Group (Mr. Stickle) B. A. Stickle	B. A. Stickle
Vicki Ammerati (Mrs. Ammerati)	V. Ammerati
Triple Five Corporation Ltd. (Triple Five) R. W. Urban Consultants Ltd.	R. Wrigley
City of Calgary (the City) E. C. Brown	E. C. Brown
Calgary Regional Planning Commission (the Planning Commission) B. Koch	B. Koch
Energy Resources Conservation Board staff C.J.C. Page D. K. Boyler M. S. Craig N. F. Lord, C.E.T.	

1 Messrs. Pawliw and Harrington represented Cimarron. Messrs. Krenkel and Ibach represented ICG. The remaining witnesses in this group are consultants hired by both Cimarron and ICG to speak to the applications.

1.5 Hearing

A public hearing of the applications was held on 22 March 1988 in Balzac, Alberta, before a division of the Board comprised of G. J. DeSorcy, P.Eng., E. J. Morin, P.Eng., and J. P. Prince, Ph.D.

1.6 Background

The proposed wells would be located approximately 4 to 6 kilometres (km) north of the Calgary city limits (see Figure). The sites are situated in the Municipal District of Rockyview with agriculture-based activities being the primary land use. This region has also been proposed for annexation into the city for residential development purposes (see Figure).

The geological formation of primary interest for the three wells is the Elkton. The applicants have defined an Elkton anomaly believed to be a new pool which would be intersected by all three wells. Subsurface targets were defined by geological and geophysical interpretations. Both an oil zone and gas cap are expected to be present in this new pool.

Data from offsetting wells penetrating the Elkton in the area of application indicate that hydrogen sulphide (H_2S) may be expected in both the Elkton and Ellerslie Formation (Ellerslie). Within the study area the only indication of H_2S in the Ellerslie occurs in a well located in Lsd 10-35-25-29 W4M where an analysis of drill-stem-test gas resulted in a value of 1.06 per cent H_2S. H_2S values for the Elkton were shown to vary from 0 per cent to 2.77 per cent.

2 ISSUES

The Board considers the issues with respect to the applications to be

- the purpose and need for the wells,
- the proposed surface and bottom-hole locations,
- the drilling of the wells,
- the emergency response plans,
- the production of the wells, and
- the impacts of the wells and measures to reduce them.

3 PURPOSE AND NEED FOR THE WELLS

3.1 Views of the Applicants

Cimarron and ICG submitted that the purpose of the proposed wells was to develop the reserves believed to underlie the drilling spacing units (DSUs). The mineral rights to the DSUs had been acquired by entering into various pooling agreements. Cimarron stated that it was subject to contractual agreements which stipulate that the lands must be developed before lease expiry dates terminating in 1989. ICG submitted that although the leases for the lands it held did not expire until 1992, it

wished to commence drilling operations in order that the lands be developed as soon as possible. Both Cimarron and ICG stated that there was an obvious economic need to drill and produce the reserves which both companies hope exist.

Cimarron and ICG said the drilling of the wells would provide valuable geological information which would assist in determining the scope and nature of reserves in the area. If reserves did not exist, this knowledge would be useful for determining if further exploratory drilling was warranted. This would also be beneficial in determining how surface development might proceed in the future. If reserves are present, then there is a need to find and produce those reserves as expeditiously as possible.

3.2 Views of the Interveners

Generally, the interveners did not dispute the need for the wells as these applied specifically to each company. They did, however, dispute the need for any drilling which may encounter H_2S in what they considered to be a highly sensitive area. They also questioned whose rights should take precedence in such a situation: those of the surface owner or those of the mineral right holder. They raised questions as to what effects the presence of such wells could have on the environment, health, safety, livestock, and general lifestyle in the area. Further, they questioned the need to develop these specific reserves when in their opinion markets for presently established gas reserves could not be found.

The City submitted that it was not opposed to the drilling of the wells provided that it was recognized that as urban development became imminent in the area, urban use would have a higher priority than sour gas operations.

The Planning Commission submitted that it had no objections to the drilling of the wells and that it supported rapid depletion of reserves in areas where serious conflict between sour gas and urban development could occur in future.

Triple Five did not question the applicants' need for the wells but submitted that its primary concern was related to the anticipated conflict between resource development and urban surface development.

3.3 Views of the Board

The Board accepts that the applicants have the necessary lease arrangements to allow them to explore for and recover any reserves which may underlie the subject DSUs. It believes that the recovery of such reserves would represent economic benefits to the province.

The Board also believes that the drilling of the wells would provide geologic information which would be beneficial in determining what, if any, hydrocarbon development might occur in future. This is especially pertinent in this area which has potential for increased urbanization.

Given the above, the Board accepts the proposed purpose and need for the wells. However, the potential adverse impacts of the wells must be considered along with any mitigative measures which would offset these impacts. If such measures cannot reduce the impacts to acceptable levels, then the exploration for and development of reserves may have to be foregone.

4 PROPOSED SURFACE AND BOTTOM-HOLE LOCATIONS

4.1 Views of the Applicants

Cimarron and ICG submitted that as surface leases had been obtained for the proposed sites, the applied-for surface locations were appropriate. Cimarron submitted that it had originally intended to drill a conventional vertical well but was unable to obtain a surface lease from Mr. Stickle, owner of the northeast quarter of section 16. Mr. Stickle had raised concerns respecting the wells proximity to dwellings on the quarter section, and possible environmental impact. Cimarron therefore proposed to directionally drill the well from a surface location in the northwest quarter of section 15.

The applicants submitted that the bottom-hole locations for the wells were determined on a geological basis in order to minimize the risks associated with drilling these exploratory wells. As the bottom-hole locations were not disputed by the interveners, and as these had been determined by the companies using the best technical data presently available, Cimarron and ICG submitted that the bottom-hole locations were appropriate.

4.2 Views of the Interveners

Generally, the interveners from the area objected to the proposed surface locations of the wells as being too close to the lands on which they resided. However, they did not submit any alternative surface locations for consideration. Their primary concern was the adverse impacts which any wells in the immediate area would have on their lands, health, and safety.

The City, the Planning Commission, and Triple Five also did not dispute the specific surface locations of the wells. However, concerns were raised as to the possible implications to future urban development as a result of the presence of the wells. These could include possible impacts due to setback distances imposed by the municipal authorities.

None of the interveners questioned the appropriateness of the bottom-hole locations from a technical perspective.

4.3 Views of the Board

The Board notes that the major concerns respecting the location of the wells pertain to the impacts on the environment and persons in the area, and possible future urban development. These impacts will be addressed in Section 8.

The geology of the region limits the possible bottom-hole, and therefore surface, locations to a relatively small area in the vicinity of the proposed locations. Since no specific alternative locations were submitted for the Board to consider, the Board assumes that those proposed would be as acceptable as any others, and will assess the impacts on that basis.

5 DRILLING OF THE WELLS

5.1 Views of the Applicants

Cimarron and ICG submitted that every reasonable precaution would be taken to ensure that the wells are drilled in a safe, efficient, and nuisance-free manner. To this end, the applicants submitted that very comprehensive and conservative drilling and on-site safety plans had been prepared to ensure that the safety of area residents and property would not be jeopardized. In recognition of the sensitivity of the area and proximity to urban development, the applicants noted that the wells are classed as critical. Therefore the drilling and safety plans have been designed to provide for encountering the maximum potential H_2S release rates that could be expected for the area and the geological zones to be penetrated. All major recommendations of the Blowout Prevention Review Committee and Alberta Recommended Practices for the drilling of critical sour wells will be followed.

The applicants noted intermediate casing is normally required in wells classed as critical. Cimarron and ICG requested that the Board consider an alternative which would provide the best of both worlds in cost effectiveness and drilling safety. They proposed that surface casing be set at a depth of approximately 460 metres (m) which would be considerably deeper than what would be normally required by the Board in this area. Drilling would then proceed to approximately 100 m above the Elkton. At that point the wellbore would be conditioned and operations suspended to allow for a complete assessment of the situation. This would include ensuring that the wellbore was stable, no lost circulation was taking place, and no over-pressured formations had been encountered. If deemed safe to do so, drilling would proceed into the Elkton and production casing set to total depth or the wells abandoned, depending on the success of the wells. If at the point of suspension of operations there were indications of wellbore or other relevant problems, intermediate casing would be set prior to penetration of the Elkton.

This approach would, in the applicants' opinion, ensure the intermediate casing would be set if there was evidence it was needed to provide an extra margin of safety, but would avoid the need to install intermediate casing if it served no useful purpose. Cimarron and ICG submitted that a review of the drilling records of over sixty wells penetrating the Elkton in the Crossfield area had indicated that no problems should be expected. The applicants submitted these wells had been drilled safely using only surface casing set at shallower depths than proposed for the applied-for wells.

Cimarron anticipated its well would require approximately 26 to 34 days to drill, including provision for some additional time because the well is being directionally drilled. ICG proposed to drill vertical wells and anticipated drilling operations to require 23 to 32 days for each well. ICG stated it proposed to drill the 6 of 10 well first and then evaluate the geologic results before proceeding with the 14 of 10 well.

Cimarron and ICG also proposed that if information obtained while drilling indicated that the reserves which were encountered were somewhat less than anticipated, it was the intention to apply to the Board to have the wells declassified as critical wells. Should this be approved, they would then be allowed to perform drill-stem testing of the potentially productive open-hole sections in the wellbores. This, however, would only occur if the reservoirs were found to be of marginal quality.

Cimarron and ICG stated that concerns raised respecting possible damage to water wells in the area due to drilling activity could readily be addressed by the testing of the water wells before and after drilling operations. To this end, Cimarron and ICG committed to the testing of the water wells of any concerned parties. Testing would provide appropriate baseline data should problems be detected.

5.2 Views of the Interveners

Generally, the interveners did not question the technical merits of the drilling plans for the proposed wells. They did, however, raise concerns respecting the possible effects on health, safety, and the environment should an accident occur which resulted in a release of H_2S while drilling.

Mr. Stickle noted that there was a possibility of sloughing shales and as the Cimarron well was to be drilled directionally, complications could result.

Mrs. Ammerati submitted that as her residence was the closest to the proposed 6 of 10 well and if an accident did occur, her family would be most affected.

Mrs. Niedzwiecki submitted that she and her family earned their livelihood by raising and breeding mink. She suggested that the noise and general disturbance from drilling activities could have serious detrimental effects on their operations. This could be especially critical at breeding times or when the female mink were caring for the young kits. Further, any disruption of their farm's water supply would be very detrimental as water requirements on their ranch could be high.

The City and Triple Five did not question the technical merits of the proposed drilling plans.

The Planning Commission requested that if the wells were to proceed, the Board prescribe measures to ensure their safe drilling.

5.3 Views of the Board

The Board has reviewed the drilling plans in detail and, subject to the following comments, is generally satisfied with the technical merits of the plans.

5.3.1 Intermediate Casing

With respect to the request to provide for possible waiver of the intermediate casing, the Board notes that this casing serves to correct many potential problems, including:

- o sloughing shale,
- o excessive torque and/or drag on the drill pipe,
- o lost circulation,
- o crooked hole, and
- o abnormally high or low formation pressures.

It also facilitates shutting in the well at surface if a blowout occurs, to minimize the impact on workers and the public.

At the point of decision suggested by the applicants, the actual experience with or potential for these problems will be known only with respect to that portion of the well above the critical zone, and not with respect to the critical zone itself. In some areas of the province where critical wells are to be drilled in a well-known pool (ie. development drilling) and the well is in a remote area, waiver of the intermediate casing may be appropriate. However, the subject wells do not meet those criteria. The area is well populated, and the wells are intended to penetrate a new pool. Accordingly, waiver of the intermediate casing would not be appropriate.

If one of the wells is drilled prior to the other two, the Board would be prepared to reconsider the question of waiver of the intermediate casing for the second and subsequent wells, provided sufficient time is allowed between the first and second wells to thoroughly analyse results of drilling the first well.

5.3.2 Drilling in the Critical Zone

The Board also has concerns respecting the timing of drilling operations and would not endorse drilling in the critical zone for two or more of the subject wells at the same time. The Board would therefore expect the applicants to co-ordinate the timing of drilling activities to ensure that at any one time the critical zone of only one well is open to the wellbore without production casing or cement plugs in place.

5.3.3 Drill-stem Testing

With respect to the applicants' request to provide for declassifying the wells to permit drill-stem testing, the Board finds that it does not agree with the proposal. The wells could not be declassified until the

flow rate is known with some certainty. The flow rate would not be known until after the wells are drill-stem or production tested. Therefore the Board is not prepared to grant a request for declassifying the wells at the stage requested by the applicants.

6 EMERGENCY RESPONSE PLANS

6.1 Views of the Applicants

Cimarron and ICG submitted that very conservative and extensive emergency response plans (ERPs) had been prepared to completely protect the residents in the area. This would be accomplished by a three-step process. First, the plans incorporated extremely conservative (high sided) estimates of the maximum potential release rates for the wells to establish the appropriate emergency planning zones (EPZ). Based on available data, a total release rate for both the Elkton and Ellerslie was estimated at 0.388 cubic metres per second (m^3/s). In accordance with the guidelines set out by the Board, an EPZ of 1250 m radius was established.

The second step would be to provide as much time as possible to deal with a potential release of H_2S. This would be accomplished by delineating a three-stage alert program, based on the events occurring at the well. A Level 1 alert would involve the detection of early warning signs of a potential problem while drilling. At that point, the proper authorities would be given notice, air monitoring would commence, and residents within the EPZ who have indicated a particular sensitivity to H_2S would be notified. A Level 2 alert would ensue if the potential well control problems escalated to a point where control of the well was suspect. At that stage all residents in the EPZ would be notified and asked to evacuate. Additionally, access to the area would be restricted. A Level 3 alert would be established if complete control of the well was lost or if only partial control was possible and it was apparent that there might be problems in regaining control in an expeditious manner. At that point, all persons in the EPZ would have been evacuated and all agencies notified of the escalation of problems.

The applicants submitted that the third main step in the plan to ensure area residents' safety was the establishment of stringent ignition criteria for the wells, such that if at any time there was a threat to public safety, either inside or beyond the EPZ, the well would be ignited.

Based on this conservative approach to emergency planning and the severe ignition criteria, Cimarron and ICG believed the drilling of the wells should pose no threat to the area residents or environment.

6.2 Views of the Interveners

The interveners raised concerns as to the serious effects an accident could have on their safety if a release of H_2S occurred. They also

pointed out that the ERPs did not adequately provide for their livestock which could be seriously affected should H_2S escape from the wells.

The City questioned the need to change the ERPs so as to include the City police and fire departments if the lands were annexed.

Triple Five questioned the appropriateness of the 100-ppm isopleth used in determining the emergency planning radius.

6.3 Views of the Board

The Board notes that if the applications were to be approved, before the wells were licensed finalized ERPs would have to be submitted for approval. Therefore, modifications to the ERPs can be made, based on the hearing evidence.

The Board accepts that given the available data, the sizes of the planning zones are appropriate. The Board believes, however, that in recognition of the wells' proximity to urban areas, it would be appropriate to expand the scope of the ignition criteria to provide for ignition of the wells if an H_2S level of 1 part per million is recorded for 1 hour at the limits of residential development in the cities of Calgary or Airdrie.

Given this additional measure, the Board believes the ERPs to be reasonable and practical in their approach to safety should a release of H_2S occur.

7 PRODUCTION OF THE WELLS

7.1 Views of the Applicants

The applicants submitted that if the wells are found to be productive, efforts would be made to ensure the least possible impact from any production testing or permanent production facilities that may follow.

If the reservoir contains gas, the applicants stated that a 48-hour production test would be sufficient to acquire enough information for future planning purposes. If the reservoir contains essentially oil, a 30-day test period could suffice instead of the standard 90-day production test period usually employed by industry.

Should gas be found, facilities would essentially consist of a wellhead with the gas being pipelined to the nearby Petrogas plant for processing. If oil was to be produced, both ICG and Cimarron would, after economic quantities had been confirmed, attempt to co-ordinate activities and to develop a central site for treating and storage of the oil. Each well site would consist primarily of a pump jack with power being provided by fuel gas or electricity if practical. Vapour recovery would be utilized to ensure odour-free production operations.

Cimarron and ICG noted that the facilities were expected to be classified as Level 1 according to the Board's H_2S guidelines. Therefore, setback distances were no more onerous than those imposed by a sweet well.

Given these factors, ICG and Cimarron believed that the facilities should not have any serious impacts on the surrounding area.

7.2 Views of the Interveners

The area residents raised concerns about the impacts such facilities could have on them over the long term. They believed that they could be subjected to odours and noise from the facilities, which would greatly affect the lifestyle they currently enjoyed. Further, the existence of the facilities would detract from the aesthetics of the area and would have a negative impact on their property and the value of their lands.

The City submitted that at some time in the future, it would be appropriate to remove the facilities even prior to depletion of the reservoir to ensure no adverse impact on aesthetics or ability to develop the surface.

The Planning Commission submitted that the Board should ensure that provision is made for the safe construction and operation of the proposed facilities.

Triple Five suggested that the existence of the facilities would result in a reduced attractiveness of the area for future residential development.

7.3 Views of the Board

The Board notes that until actual reserves are encountered, testing and production scenarios are matters of speculation, as approval of production facilities is subject to future applications once actual information is obtained. The Board believes, however, that operators should be fully aware of the possible ramifications of drilling in what is considered a sensitive area.

Respecting production testing, the Board would require that it be advised of testing procedures and proposals prior to the commencement of operations. The Board would approve production testing for gas only if absolutely necessary and then under closely controlled circumstances.

The Board believes a 30-day test period for oil as suggested by the applicant would be appropriate. The applicants should ensure that over this period all efforts are undertaken to ensure their operations cause no impacts. Noise, trucking, and flaring would be kept to a minimum.

Regarding permanent production facilities, the Board would expect operators to plan ahead and co-ordinate their efforts. Facilities would be constructed and maintained in accordance with good oil-field

practices. The operators would be required to have special regard for the containment of odour, suppression of noise, and the general appearance of the facility. Moreover, the Board would not favour construction of a multitude of single-well batteries if oil is discovered. Operators should be aware that the Board may not be prepared to approve such applications for any length of time and therefore it would be prudent to investigate establishing central facilities and appropriate pipeline routes at an early stage.

8 IMPACTS OF THE WELLS AND MEASURES TO REDUCE THESE

8.1 Views of the Applicants

Cimarron and ICG submitted that because of the conservative planning that had gone into all phases of the proposals, the negative impacts on the surrounding area and residents would be minimal. The conservative estimates used in H_2S calculations had resulted in drilling programs, on-site safety programs, ERPs, and production plans that would ensure that the wells could be drilled and produced in a safe manner. ICG and Cimarron stated that they believed the concerns expressed by area residents were genuine and therefore they were committed to co-operate with these persons to reduce any perceived negative impacts to a minimum. That co-operativeness was confirmed by Cimarron's and ICG's willingness to test water wells, limit production testing periods, obtain baseline data for the Niedzwiecki mink farm, and generally inform surrounding residents about the workings of their operations.

Respecting the City's proposal for a limited 15-year period for production, Cimarron and ICG submitted that it would be premature to set a definite time period. It would, however, be appropriate to address these matters in future at such time as urbanization may be in conflict with resource development. This would, in their opinion, be more prudent; as factors such as future urban expansion, the nature of possible conflicts, actual reserves, and economics of the public and energy sectors are currently unknown.

8.2 Views of the Interveners

The area residents believed that the drilling and possible production of the proposed wells would have a very extensive impact on themselves and their land. They perceived the impacts to be such that they believed the Board should not approve the applications.

Mrs. Ammerati submitted that she was extremely sensitive to H_2S and therefore the presence of the well and related facilities would always present a great concern to her for her health and safety. In addition, such impacts as increased noise and traffic would generally degrade the lifestyle of persons living in the area. These negative aspects could also reduce the value of property in the area, adding additional hardship due to the presence of the facilities.

Mrs. Niedzwiecki submitted that the proposed wells could essentially destroy their mink breeding operation should a mishap occur. She questioned the effects the wells could have on their animal stock and submitted that there was insufficient information available to predict what effects could occur.

Mr. Stickle submitted that the wells could have very detrimental effects on health, safety, the environment, and property values. Given the area's potential for annexation and urban development, it was not appropriate for the Board to approve any such application. He was concerned that abandonment procedures at the end of the production phase would not isolate the acid gas forever.

The City stated that urbanization should take precedence over energy development in the area. It requested that the Board impose a limit of 15 years for production operations. After that, a rigorous examination should be initiated to determine if production of the wells could continue. The City also insisted that it be consulted as part of that review process.

The Planning Commission stated that it recognized the importance of energy development in the area and stated that from a land-use perspective it had no objections to the wells. The Planning Commission believed, however, that the potential for serious land-use conflicts does exist. The Planning Commission therefore requested that the Board ensure that the length of time any such facilities be allowed to produce would not be excessive.

Triple Five stated that its primary concern was with respect to the anticipated conflict between resource and urban surface development. It submitted that negative impacts such as noise, traffic, odour, and visual impact of production facilities could reduce the marketability of properties. Because of setback requirements, direct physical conflict could also occur. Triple Five submitted it would be appropriate for the Board to defer its consideration of the applications until objective studies were prepared to explicitly outline the potential impacts on future development.

8.3 Views of the Board

The Board recognizes that when energy developments are proposed for an area, they may affect the surrounding region. When the developments are close to urban areas it is important that operators be aware that special measures to reduce any negative effects may be required and the resulting costs may be especially high.

Respecting these specific applications, the Board has given particular attention to the concerns raised by the interveners. Given the special care which would be taken in the drilling of the wells, the chances of an accidental sour gas release would be very small. In the unlikely event of an accidental release, the ERPs are such that there should not

be a serious threat to the safety of the public. This is particularly true in this case, because of the low H_2S level expected and the very stringent ignition criteria which would be utilized.

If a sour gas release was to occur, it is recognized that there could be some impact on land, livestock, and other property. If such impacts did occur, they would have to be compensated for by the operators of the wells. Recognizing this, and in keeping with its policy respecting the licensing of critical sour wells, the Board would issue the licences only after satisfying itself that the applicant companies have sufficient financial resources and/or insurance to handle any potential costs.

One of the concerns expressed was the potential adverse effect of ongoing producing operations on the health of residents of the area. Given the expected low H_2S content, and the special operating controls that would be required, the Board does not believe that there would be any such adverse effects. It is influenced in this regard by its knowledge of the results of the Twin Butte medical study which demonstrated that the health of people in a long-term sour gas producing area was generally not different than for those in non-sour gas areas.

Regarding the effectiveness of abandonment, the Board acknowledges that problems with well sites abandoned in the early 1900s have occurred. But, with modern procedures and regulations governing abandonment that were not in place in the early part of the century, the Board is confident that these problems will be almost non-existent in future.

Operators in the area would have to adhere rigidly to the Board's noise guidelines. This should minimize problems related to noise. In terms of potential impacts on water wells, the Board notes the applicants' willingness to test any water wells in the region prior to commencing drilling. The Board would not expect that water wells would be impacted by the proposals but this would establish a baseline from which to measure any problems that may occur.

The question of reduced property values was raised by some interveners. This is always a difficult matter to deal with. On the one hand, site-specific downward pressure on property values might occur because of an immediately present industrial operation. At the same time, the overall beneficial economic impacts of industrial operations on a region undoubtedly creates an upward pressure on property values.

In the specific case at hand, and recognizing that few noise, odour, or other impacts would be expected from the operation, the Board would not expect significant negative impacts on property values. Additionally, no evidence was presented at the hearing or at other hearings demonstrating that oil and gas activities cause lower property values.

Considerable concern was raised respecting possible impacts on an existing mink ranching operation located some 1.4 km from the closest of the proposed wells. The Board recognizes that there is some potential

for such impacts but with careful adherence to all of the regular and special controls which would be applied during drilling and producing operations, the Board does not believe negative impacts are likely. If they did occur, the Board expects they would be compensated for. In this regard it notes the applicants' willingness to engage a third-party expert at their expense to review the existing mink operation and establish baseline data for it. Although it does not expect significant impacts, the Board believes the gathering of such data would be worthwhile and urges the Niedzwieckis and the applicants to co-operate to obtain such data.

The Board has also considered the concerns of the City of Calgary, the Calgary Regional Planning Commission, and the Triple Five Corporation Ltd. regarding potential impacts on future urban development and in particular the City's request that operations be limited to a 15-year period. The Board recognizes that, in the future, conflicts between oil and gas operations and high density urbanization may develop. However, the Board believes it would be inappropriate to set specific dates for terminating operations at this time, when many of the factors which could influence the situation are unknown. For example, not only is the pace of urban development uncertain, but at this stage it is not even known if the area is underlain by oil or gas reserves.

The Board believes it would be more appropriate if it indicated a preparedness to review the situation in 15 years, but only if requested to do so by the City or some other involved party. As part of such review, the Board would consider such factors as proximity to urban developments, reserves in place and produced to date, and the operational records of operators. The Board would not intend to automatically require abandonment of the operations simply because urban developments are within some prescribed distance to them. However, it would evaluate the situation, and if the then existing circumstances demonstrated that ongoing co-existence of different land uses was not reasonable, it would be prepared to direct discontinuance of operations, even though the recovery of oil or gas would be reduced.

9 DECISION

Having reviewed the evidence, the Board concludes that the wells can be drilled, tested, and produced in a safe manner with minimal impacts on residents of the area or the environment. It is therefore prepared to approve the applications, subject to all of the undertakings given by the applicants in their applications and at the hearing and to the conditions described in this decision report, including the following specific ones:

- o The requests to waive intermediate casing are denied, except in accordance with conditions noted in this report.
- o No two of the wells will be permitted to carry out drilling operations in the critical zone at the same time.

- No drill-stem testing of the wells is to be performed.

- The emergency response plans are to be revised to require ignition of the wells if H_2S levels reach 1 part per million for a 1-hour period at the limits of residential development of Airdrie or Calgary.

DATED at Calgary, Alberta, on 6 July 1988.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Chairman

B. J. Morin, P.Eng.
Board Member

J. P. Prince, Ph.D.
Board Member

APPLICATION FOR WELL LICENCES. Cimarron Petroleum Ltd. and ICG Resources Ltd.

D 88-11

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

OTHER SIX LEASES OPERATION
APPLICATION TO CONSTRUCT A
DREDGING/COLD WATER EXTRACTION
EXPERIMENTAL FIELD TEST

Decision D 88-12
Application 880397

1 INTRODUCTION

1.1 Application

Other Six Leases Operation (OSLO) applied to the Energy Resources Conservation Board (the Board), pursuant to sections 10 and 11 of the Oil Sands Conservation Act, for approval to conduct a small, simulated dredging/cold water extraction experimental field test in the northwest quarter of section 6, township 91, range 9, west of the 4th meridian.

The scheme would involve simulated dredging of in situ oil sands from an abandoned borrow pit. Bitumen extraction would be accomplished by introducing air and chemicals into the slurry-transporting pipeline. The resulting bitumen froth would be stored in a pond and ultimately trucked to Syncrude for further upgrading.

OSLO also proposed to conduct a high-pressure water jet cutting test. However, detailed plans of this test were not provided.

OSLO has requested an approval period of 3 years.

1.2 Background to the Application

OSLO indicated that in 1984, it began studies to develop new technology to reduce overall bitumen production costs. Laboratory research led to the development of a new bitumen extraction process called "OSLO Cold Water Extraction" (OCWE). Based on the potential shown by the OCWE process, OSLO is entering the second year of a 4-year technology development program for the dredging/OCWE system. If the proposed experimental tests now being applied for are successful, a demonstration pilot, using a dredge with a capacity of 600 tonnes per hour, would be designed for operation on Lease 31 in 1989. That pilot would be the subject of a separate application if a decision were made to proceed.

2 HEARING

The application was considered at a public hearing on 6 July 1988 in Calgary. Sitting were N. A. Strom, P.Eng., J. P. Prince, Ph.D., and T. F. Homeniuk, P.Eng. (Acting Board Member). Following is a list of the participants at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used In Report)	Witnesses
Other Six Leases Operation (OSLO) J. Ballem, Q.C.	W. Jazrawi, Ph.D. K. Sury J. Hrouda, P.Eng.
C-H Synfuels Ltd. (C-H) W. Major, Q.C.	S. J. Lane, P.Eng.
Energy Resources Conservation Board staff M. Bruni B. Gartshore, P.Eng.	

3 PRELIMINARY MATTERS

At a pre-hearing meeting held on 6 June 1988 concerning an allegation by C-H regarding potential predation of intellectual property, the Board ruled that it would not hear evidence or make any judgement on issues dealing with intellectual property.

4 DECISION

At the conclusion of the hearing, the Board ruled that it would grant the application subject to the test being conducted in accordance with the description and supporting detailed information submitted by OSLO in the application. The Board also advised that OSLO would be expected to apply for approval prior to making any changes to the test and that C-H would be given notice of any such application.

5 REASONS FOR DECISION

The details of operation of the project, its potential impact on the surrounding environment, and plans to reclaim the site were addressed in the application and through responses to deficiency letters issued by the Board prior to the hearing. Therefore, the Board believes that the only issue to be considered is the contention of C-H that OSLO's proposal would be a duplication of the recently approved C-H test (Decision D 88-10) and that it would not, therefore, be in the interest of Albertans to approve it.

C-H was concerned that, if OSLO's application were approved, it would be a relatively simple matter for OSLO to have its approval amended to allow testing similar to that proposed by C-H. C-H contended that such duplication in testing would not be in its interest nor in the interest of Albertans.

C-H stated that it would not object to approval of OSLO's application, provided that OSLO is restricted strictly to the equipment, tests, and methods of testing, including the small diameter slurry pipeline, it

described in the application. C-H stated that its concerns relate to the fact that it is already known that the process proposed by OSLO will not work on a commercial scale. C-H argued, for example, that the introduction of air as a flotation aid may not work in a large diameter pipeline.

OSLO stated that the primary objective of its proposal is to test the OCWE extraction process which would employ extraction temperatures in the range of 5^{o} to $15^{o}C$. Chemicals would be added to the extraction process that are unique to the OCWE process and lime would not be added to the tailings treatment. OSLO also stated that the only similarity between its proposed test and that recently approved for C-H is that both would use an Ellicott dual bucketwheel suction dredge cutter head to mine the oil sands. It submitted that this is a standard manufactured item available "off the shelf" and use of it should not be considered a duplication of what C-H is proposing to do.

Because OSLO was willing to restrict its activities to the tests and method of testing proposed in its application, the concerns of C-H were addressed and the Board was able to tender its decision without considering whether or not duplication of testing would occur and, if so, whether or not that would be adverse to the public interest of Albertans. As indicated at the conclusion of the hearing, OSLO would be expected to obtain ERCB approval prior to making any changes to its test project and C-H would be given notice.

6 APPROVAL

The Board reaffirms its decision given at the conclusion of the hearing. The Board is prepared to grant the application and authorize it subject to the undertakings agreed to at the hearing, and subject to the conditions set out in the attached draft Approval No. 5715.

DATED at Calgary, Alberta, on 12 July 1988.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

J. P. Prince, Ph.D.
Board Member

T. F. Homeniuk, P.Eng.
Acting Board Member

THE PROVINCE OF ALBERTA

OIL SANDS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of an experimental scheme of Other Six Leases Operation for the recovery of crude bitumen from the Athabasca-Wabiscaw-McMurray oil sands deposit in the Fort McMurray Area

APPROVAL NO. 5715

WHEREAS the Energy Resources Conservation Board is prepared to grant an application by Other Six Leases Operation, subject to the terms and conditions herein contained.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Oil Sands Conservation Act, being chapter O-5.5 of the Statutes of Alberta, 1983, hereby orders as follows:

1. The experimental scheme of Other Six Leases Operation (hereinafter called "the Operator") for the recovery of crude bitumen from the area shown outlined on the attachment hereto, marked Appendix A to this approval, as such experimental scheme is described in Application No. 880397 dated 29 February 1988 and addenda thereto dated 6 May 1988, 16 May 1988 and 6 June 1988, is approved, subject to the Oil Sands Conservation Regulations and the terms and conditions herein contained.

2. The Operator shall commence experimental operations on or before 1 July 1989 unless, upon application by the Operator, a later date is approved by the Board.

3. The Operator shall supply to the Board, for its approval, a geotechnical evaluation, conducted by a geotechnical engineer prior to commencement of site construction activity, regarding the impact of the project on the stability of the existing escarpment slope.

4. The Operator shall, in accordance with section 21 of the Pipeline Regulations, erect temporary fencing of the existing pipeline right of way located at the south end of the project area.

5. The Operator shall store in tanks, or in a manner approved by the Board, until sold or disposed of as described in the application, all liquid hydrocarbons recovered from the operation of this scheme and not usefully consumed in the operation or in works or installations used in connection with the scheme.

6. The Operator shall dispose of all excavated material in a safe and environmentally acceptable manner satisfactory to the Board.

7. The Operator shall provide to the Board, for its approval, detailed plans regarding the high pressure water jet test not less than 30 days prior to commencement of the test.

8. The Operator shall

(a) file progress reports with the Board for each six-month period of operation commencing with the period 1 July 1988 to 31 December 1988,

(b) file the progress reports required by subclause (a) within 60 days of the expiration of each six-month period or within 120 days of the termination or continuous suspension of experimentation, whichever shall occur first, and

(c) set out in the progress reports required by subclause (a)

(i) a description of construction progress,

(ii) a chronological report of all activities and operations conducted, and

(iii) the results of any measurements or observations which are pertinent to the interpretation of the experimental operations.

9. Data submitted pursuant to

(a) Application No. 880397 dated 29 February 1988,

will be released on 31 July 2001 unless, upon application by the Operator or if other circumstances so warrant, a later date is approved by the Board.

10. Prior to changing any element of the test procedure as described in the application, the Operator will inform the Board, and the Board may provide notice to C-H Synfuels Ltd.

11. (1) The Board may,

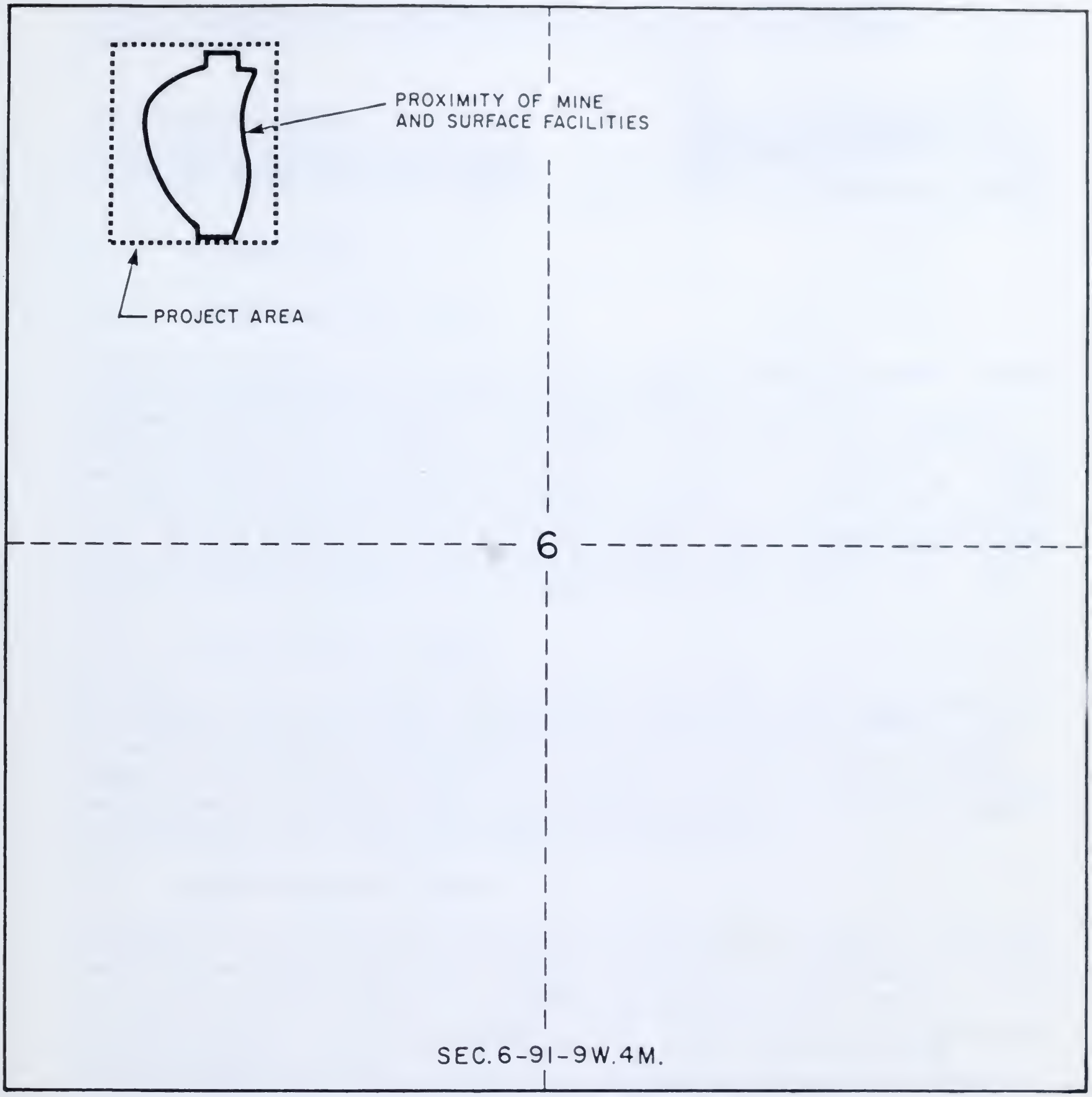
(a) upon its own motion, or

(b) upon the application of an interested person, rescind or amend this approval at any time.

(2) This approval expires on 31 July 1991 unless rescinded before that date pursuant to subclause (1).

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD



FORT McMURRAY AREA
OSLO LEASE 41 DREDGING PROJECT
APPENDIX A TO APPROVAL NO. 5715

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

PIPELINE APPLICATION
TO CONSTRUCT CRUDE OIL PIPELINES
IN THE RED EARTH AND KIDNEY AREAS

Decision D 88-13
Applications 880546, 880650, 880651, and 880674

1 INTRODUCTION

1.1 Application No. 880546

Pursuant to Part 4 of the Pipeline Act, Unocal Canada Management Limited (Unocal) submitted an application for a permit to construct approximately 25.0 kilometres (km) of 114.3-millimetre (mm) outside diameter pipeline and related facilities to transport crude oil from an existing battery in legal subdivision 8, section 24, township 90, range 6, west of the 5th meridian (Lsd 8-24-90-6 W5M),to a Numac Oil and Gas Ltd. (Numac) pipeline in Lsd 11-30-88-7 W5M. Dorset Energy Corporation, Chevron Canada Resources, and Numac supported this application. Gulf Canada Resources Limited (Gulf) opposed this application.

1.2 Application No. 880650

Pursuant to Part 4 of the Pipeline Act, Gulf submitted an application, as operator and part owner of the Wabasca River Pipeline (WRPL), for a permit to construct approximately 8.0 km of 114.3-mm outside diameter pipeline and related facilities to transport crude oil from an existing battery in Lsd 8-24-90-6 W5M to the existing WRPL in Lsd 9-8-91-5 W5M. ICG Resources Ltd. (ICG) supported this application.

1.3 Application No. 880651

Pursuant to Part 4 of the Pipeline Act, Murphy Oil Company Ltd. (Murphy) submitted an application for a permit to construct approximately 32.0 km of 114.3-mm outside diameter pipeline and related facilities to transport crude oil from a battery in Lsd 9-10-89-3 W5M to the proposed Unocal pipeline in Lsd 15-23-89-6 W5M, and from a battery in Lsd 1-30-89-3 W5M to a pipeline tie-in on the proposed Murphy pipeline in Lsd 4-18-89-3 W5M. Gulf opposed this application.

1.4 Application No. 880674

Pursuant to Part 4 of the Pipeline Act, Gulf submitted an application, as operator and part owner of the WRPL, for a permit to construct a pump station in Lsd 16-9-89-3 W5M, and approximately 13.0 km of 168.3-mm and 114.3-mm outside diameter pipeline from the proposed pump station to a pipeline tie-in on the existing WRPL pipeline in Lsd 8-18-90-3 W5M, and from an existing battery in Lsd 12-22-89-3 W5M to a pipeline tie-in on the proposed Gulf pipeline in Lsd 9-21-89-3 W5M. A common Lease Automatic Custody Transfer (LACT) facility would be installed in Lsd 16-9-89-3 W5M to collect, meter, and transport the crude oil produced by

the Canadian Roxy Petroleum Ltd. (Roxy) 13-8 battery and the Murphy 9-10 battery. ICG and Roxy supported this application.

In essence, the applications of Unocal and Murphy are a scheme for the transporting of their own oil, and that committed to them, through their own pipeline systems to the Peace Pipe Line and on to Edmonton; whereas the applications of Gulf are a scheme for transporting the same oil through the existing WRPL to the Rainbow Pipe Line and on to Edmonton.

The proposed pipelines are shown on the attached map.

2 HEARING

The applications were considered at a public hearing in Calgary, Alberta, on 28 June 1988, with Board Members F. J. Mink, P.Eng., E. J. Morin, P.Eng., and Acting Board Member H. Antonio, P.Eng., sitting.

Participants at the hearing are listed in the following table.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Unocal Canada Management Limited (Unocal)	R. Goldie
S. Wright	N. Kelly, P.Eng.
	N. Meghani, P.Eng.
Murphy Oil Company Ltd. (Murphy)	R. D. Urquhart, P.Eng.
T. Ferguson	J. Kers, P.Eng.
	B. N. Hunka, P.Eng.
Gulf Canada Resources Limited (Gulf)	P. Picherack
D. Gandar	M. Thompson
	R. Gunson, P.Eng.
Peace Pipe Line Ltd. (Peace)*	
R. Avery	
Energy Resources Conservation Board staff	
G. Habib	
N. C. Harris, P.Eng.	
A. L. Larson, E.I.T.	

*Peace appeared for cross-examination purposes only.

3 ISSUES

The Board considers the issues of the applications to be

- o the need for the pipelines,
- o the economics of the pipelines, and
- o proliferation of pipelines

The technical qualification and environmental impacts of the pipelines were not questioned. The Board is satisfied that the proposed pipelines are technically and environmentally satisfactory.

4 EXAMINATION OF THE ISSUES

4.1 Need for the Pipelines

Unocal's Views

Unocal stated that its proposed pipeline is needed to improve the economic transport of its crude oil to market in Edmonton. Presently, Unocal is trucking its oil to the Numac pipeline, in which it has a vested interest. Unocal said that its proposed pipeline would also eliminate the problems associated with trucking during spring break-up when road bans are in effect. If its application were denied, Unocal stated that it would continue to truck its oil to the Numac pipeline which would result in increased transportation costs and in lost production during the spring break-up.

Murphy's Views

Murphy stated that its proposed pipeline is needed because it would be the most economical way to transport its crude oil to market in Edmonton at this time. The pipeline would eliminate the problem of lost production during times when road bans are in effect. Murphy stated that its pipeline would service two of its batteries whereas the Gulf application for the South Trout Area would only service Murphy's 9-10 battery.

Murphy has been trucking its production to the WRPL during the 1988 spring break-up, but on 1 July 1988 Murphy intended to truck to Numac's recently constructed pipeline in which it has a vested interest. Murphy stated that if its application were denied, it would truck to the Unocal pipeline, if built, resulting in increased transportation costs.

Gulf's Views

Two Gulf applications were considered at the hearing. Gulf stated that the South Kidney extension would be built only if Gulf could reach an agreement with Unocal to transport its oil; there are no other producers in the area which could utilize this pipeline. Gulf stated that the South Trout extension would be built if Gulf could negotiate a contract with either Murphy or Roxy or both.

Gulf stated that although its South Trout application does not include the 1-30 battery, Gulf had considered the addition of the battery in placement of the proposed pipeline. Gulf believes that neither the Unocal nor the Murphy pipeline is needed because the WRPL has ample capacity to handle its production.

Board's Views

The Board finds that there is agreement by all the companies involved that pipelines are required to tie in the Murphy and Unocal batteries to

their markets in Edmonton. All the companies have addressed the need but both of the proposed Gulf pipelines are dependent on the successful negotiation of contracts with either Murphy, Unocal, or Roxy. The Board realizes that Gulf's proposed South Trout extension would only service Murphy's 9-10 battery.

The Board concludes that pipelines are needed to service both the Unocal and Murphy batteries to enhance resource development efficiency, public safety and to reduce potential hazards to the environment.

4.2 Economics of the Pipelines

Unocal's Views

Unocal stated that building its own pipeline would be the most economical means of transporting its oil. The next most economical means of transportation would be trucking the oil to the Numac pipeline at a total cost of \$10.29 per cubic metre ($/m^3$). The least economical means of transportation would be the utilization of the WRPL. Table 2 summarizes the tariffs presented at the hearing.

Although Unocal believed that the Gulf offer of \$10.64/m^3 was reasonable, it was not acceptable to Unocal because Unocal's calculated tariff for the combined Unocal, Murphy, and Numac system is still less at \$9.44/m^3. Unocal stated that it would prefer to build and operate its own pipeline than to utilize WRPL because it would get a return on its investment. In addition, Gulf cannot guarantee that its tariff would not increase.

Unocal is optimistic about future development of additional oil production in the area. Since the proposed Unocal pipeline would have extra capacity, it would be able to transport any new production by Unocal or other companies which would further reduce the financial risk of the pipeline. Unocal stated that its pipeline is economically feasible with the present production of only its 8-24 battery.

Murphy's Views

Murphy stated that it is more economic for it to build and operate its own pipeline or truck to the Unocal pipeline, if built, than to use the WRPL system. Even though the tariff of \$10.64/m^3 offered by Gulf to Murphy is comparable to Murphy's calculated tariff of \$11.13/m^3 for the combined Unocal, Murphy, and Numac system, Murphy still would have to install a lateral to connect its 9-10 battery to the WRPL. In addition, Murphy would then have only one of its batteries connected. Also, Gulf could not provide any assurance that its tariff would not increase, in the long run, especially since, according to Gulf, the WRPL is presently earning a rate of return that is not acceptable by industry standards. Murphy stated that it would prefer to build its own pipeline so it could receive a return on its investment. It also noted that equity participation in the WRPL was denied.

Murphy is also optimistic about future development in the area and believed its pipeline would be capable of handling any new production in the area, making the project even more economical.

TABLE 2 SUMMARY OF PIPELINE TARIFFS
delivered to Edmonton

	PIPELINE SYSTEM		TRUCKING
	Unocal/Murphy	WRPL	
	($\$/m^3$)	($\$/m^3$)	($\$/m^3$)
Unocal Oil Production	9.44	10.64	10.29[b] (via Numac)
Murphy Oil Production	11.13	10.64[a]	13.09[b] (via Unocal and Numac)

a Murphy would incur additional costs to build a connection to WRPL for its 9-10 battery and to arrange for the connection of its 1-30 battery.

b Does not include Unocal's or Murphy's contribution to the operating costs of the Numac pipeline.

Gulf's Views

Gulf believed that the tariff calculations by Unocal and Murphy were optimistic and that the project life and projected production volumes were unrealistic. According to Gulf, the potential for major development in the area, in the form of a large increase in oil production, is minimal. Gulf stated that if Unocal and Murphy are allowed to build and production in the area does not increase as Unocal and Murphy have predicted, then the economics would deteriorate from marginal returns today, to returns that would put both the proposed pipelines and WRPL at risk financially. Gulf stated that it was prepared to be competitive and believed that its last offer of $\$10.64/m^3$ was very favourable with the tariffs calculated for the Unocal and Murphy system.

Board's Views

The Board accepts the view that the potential for new development in the area is favourable and therefore concludes that the granting of the Unocal or Murphy application would not put either company at risk financially. Given the last offer position by WRPL, the Board agrees with Unocal's and Murphy's views that it would be more economical for them to build and operate their own pipelines than to utilize the WRPL.

4.3 Proliferation of Pipelines

Unocal's and Murphy's Views

Murphy and Unocal stated that their proposed pipelines would be in the public interest because they would provide new pipeline access to the area north of Red Earth which is not presently served by the WRPL. The new pipelines would also provide competition in the future and help control transportation costs in the area. Neither Unocal nor Murphy want to compete with WRPL for the volumes presently handled in that system. Unocal and Murphy believed that the WRPL would not lose any of its current throughput if their pipelines are built. Murphy was trucking to the WRPL during spring break-up this year but that was a short-term contract that ended 30 June 1988. As a result, those volumes cannot be considered as part of the WRPL current throughput. In summary, Unocal and Murphy believed that their facilities would not duplicate any existing facilities and there would be no immediate impact on the WRPL if their systems are built.

Gulf's Views

Gulf believed that there would be a duplication of facilities if the Unocal and Murphy pipelines are built because WRPL has the capacity to transport their production. Gulf believed that it would not be in the public interest to build another pipeline in the area because it would endanger the financial stability of all the pipelines. Gulf believed it has tried to be competitive and it would be in the public interest for Unocal and Murphy to utilize the extra capacity in the WRPL system.

Board's Views

The Board believes that if WRPL were to serve the area north of Red Earth it would require the building of a number of long pipeline laterals. Conversely, the proposed Unocal and Murphy pipelines, if built, would have the capacity to serve this area such that there would be either shorter trucking distances or shorter pipeline laterals than those that would be required by the WRPL. The Board acknowledges that the WRPL has the capacity to accommodate the oil from both Unocal and Murphy. Nevertheless, the Board accepts the view that the proposed pipelines by Unocal and Murphy would serve an area which, to a large degree, is not presently served by pipeline. Also, the new pipelines would not impact on any production currently shipped to WRPL. The Board therefore concludes that the Unocal and Murphy pipelines, if built, would not be duplicating any existing facilities.

5 FINDINGS

Although economics favour the Unocal and Murphy proposed pipelines rather than Gulf's proposed pipelines, that could be changed by negotiation in a competitive business environment. For example, it may be possible or indeed, necessary for Gulf to accept a less favourable return on its investment or other terms in the WRPL in return for attracting the volumes produced and trucked by other producers in the area. The Board believes it is not appropriate for it to intervene in

normal business transactions unless issues are related to matters such as conservation or environmental protection or if it found that facilities would be built despite the lack of need for such facilities. In this case none of these are a problem.

The granting of the Murphy and Unocal applications would not impinge on the right or opportunity of Gulf to pursue its pipeline project. The Board realizes that the construction of any of the applied for pipelines is dependent on their commercial viability which hinges in turn on the contractual arrangements in place. The Board realizes it is these arrangements that will partially dictate which pipelines are built. The Board believes that it is not within its jurisdiction to dictate the commercial and contractual arrangements to be established between companies.

6 DECISION

The Board is prepared to grant Application 880546 by Unocal, Application 880651 by Murphy, and Applications 880650 and 880674 by Gulf. The Board will issue the permits upon receipt of Ministerial Approval by the Minister of the Environment respecting environmental matters.

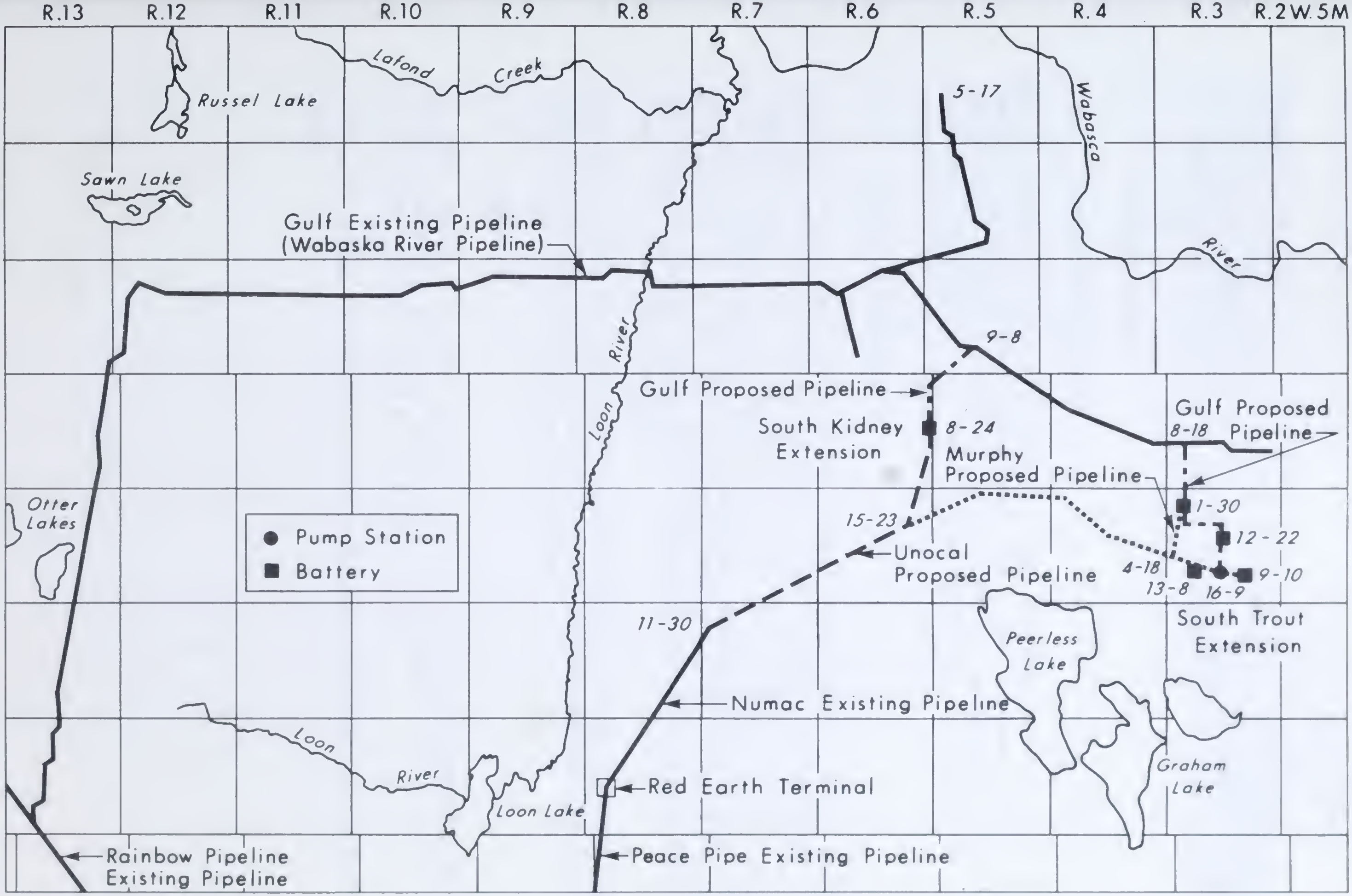
DATED at Calgary, Alberta, on 24 August 1988.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Board Member

E. J. Morin, P.Eng.
Board Member

H. Antonio, P.Eng.
Acting Board Member



PROPOSED PIPELINE ROUTES

Applications No. 880546, 880650, 880651, 880674

Unocal Canada Management Limited

Gulf Canada Resources Limited

Murphy Oil Company Ltd.

D 88-13

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

MANALTA COAL LTD.
REQUEST FOR BOARD ORDER OF A WELL ABANDONMENT — Decision D 88-14
CHINOOK MANAGEMENT LTD. — Applications 880499
APPLICATION FOR PERMIT FOR PIPELINE CONSTRUCTION — and 880920

1 INTRODUCTION

1.1 Application 880499

Manalta Coal Ltd. (Manalta) applied for an order or direction of the Board to require Chinook Management Ltd., the licensee of the well, CHINOOK RED WILLOW 6-13-40-16 (6 of 13 well), to abandon the well to facilitate mining of coal through the well site, in accordance with the mine plan approved by Mine Licence No. C 85-10.

1.2 Application 880920

Chinook Management Ltd. (Chinook) applied, on behalf of the working interest owners in the 6 of 13 well, for a permit to construct a pipeline from the 6 of 13 well to a point in legal subdivision 7 of section 14, township 40, range 16, west of the 4th meridian. The pipeline would be required to transport natural gas from the 6 of 13 well to tie in to the gas gathering system for the Newalta Red Willow Gas Plant. Chinook identified a preferred and alternative pipeline route (see attached diagram).

Chinook intends to apply for the re-licensing of the pipeline between 7-14 and the gas plant to allow for carriage of natural gas containing small quantities of hydrogen sulphide.

1.3 Hearing

A public hearing of the applications was held on 25 August 1988 in Calgary before a division of the Board comprised of N. A. Strom, P.Eng., E. J. Morin, P.Eng., and R. G. Evans, P.Eng.

A list of those who appeared at the hearing is given in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Manalta Coal Ltd. (Manalta) A. L. McLarty	P. J. Scott, P.Eng. T. Jenish J. A. Taylor, P.Eng. L. A. Shier, P.Eng.
Chinook Management Ltd. (Chinook) W. J. Major, Q.C.	J. R. Neale, C.M.A. G. D. Metcalfe, P.Eng. K. S. MacKenzie (of Esso Resources Canada Limited) W. J. Irwin, P.Eng. (of Newalta Corporation) R. E. Taylor, P.Eng. (of Newalta Corporation)
Alberta Power Limited (APL) C. K. Sheard N. E. Romanow	R.K.M. Bellows, P.Eng.
Fording Coal Limited (Fording) P. J. McIntyre	J. H. Gray, P.Eng.
Luscar Ltd. (Luscar) R. C. Secord	K. E. Hebil, P.Geol. K. G. Crane
Haeberles B. L. Anderson	M. J. Haeberle
Energy Resources Conservation Board staff C.J.C. Page B. E. Madu, P.Eng. T. J. Pesta, P.Eng. K. Jamil, P.Eng. A. Kwaczek	

1.4 Positions of the Parties

1.4.1 Manalta

Manalta, as operator of the Vesta Mine, objected to Chinook's application on the basis that a pipeline located along either of the preferred or alternative routes identified in Chinook's application would interfere with mining operations according to Manalta's "Base Case" mine plan (the Base Plan). Manalta noted that the proposed alternative pipeline route would not interfere with the present mine workings, but would eventually interfere with the continuation of mining activities.

Although Manalta originally scheduled stripping of soils from the Chinook well site during the fourth quarter of 1988, it noted that these operations could be conducted in the well area immediately prior to overburden removal scheduled to commence in mid-1990.

1.4.2 Fording

Fording, the freehold lessor of coal rights in section 13, supported Manalta's application and believed that mining through the well would be the most efficient and economic means of recovering the resources.

1.4.3 APL

APL, the lessee of coal rights in section 13, originally objected to Chinook's pipeline application but subsequently modified its position and was receptive to a plan that would allow Chinook to produce its well commencing immediately and continuing until mid-1990, suspend or temporarily abandon the well, and then after 1992, when mining operations and reclamation activities would be completed, re-enter and resume production. APL stated at the hearing that it would be prepared to absorb 50 per cent of the costs of any option for suspension or temporary abandonment of the well and re-routing of the pipeline as directed by the Board on the general understanding of all parties that the combined coal and gas least-cost option would be the most beneficial to coal and natural gas interests.

1.4.4 Chinook

Chinook originally objected to Manalta's application because it directly affects Chinook's ability to produce gas from the 6 of 13 well. However, Chinook recognized that interruption of the gas well production operations would have to occur to accommodate continued mining operations in sections 13 and 14. Recognizing the timing of those operations, Chinook stated it would prefer to commence production as soon as possible and continue for at least 18 months, suspend or temporarily abandon the well to allow continuation of mining according to the Manalta Base Plan, and then resume gas production thereafter. During the hearing, Chinook expressed agreement with Manalta that the least-cost option for continuation of both coal mining and gas well producing operations would be the most suitable pursuant to APL's undertaking to share 50 per cent of those costs.

1.4.5 Haeberles

The Haeberles, who are freehold gas royalty owners in section 13, expressed an interest in the immediate production of the gas from the 6 of 13 well in order to receive and enjoy royalty payments.

1.4.6 Luscar

Luscar is the operator of the Paintearth Mine (see attached diagram), and received a mine permit in 1978. Luscar originally objected to Chinook's application because it was concerned that a pipeline from the 6 of 13 well to a point in legal subdivision 7 of section 14 following either applied-for route would cause substantial disruption and increased costs to Luscar's proposed mining operations scheduled to commence in the Paintearth Mine West Block in 1996. At the hearing Luscar requested that any pipeline construction permit issued to Chinook providing for a pipeline in the southeast quarter of section 14 also include a provision that the pipeline be removed by 1996 or such later date at which Luscar would commence mining in the Paintearth West Block.

1.5 Background

The Board granted Manalta Licence No. C 84-18 in February 1985 for the Vesta Mine, and as a condition required the submission of information, prior to 31 March 1985, respecting the effect of the 6 of 13 well upon the 5-year mining plan and alternative mining schemes that would allow production from the well. Manalta presented a preferred Base Plan, which proposed mining through the 6 of 13 well with the need to either temporarily or permanently abandon the well by 1990.

A public hearing of the application took place in June 1985 to hear representations from interested parties respecting the coal and gas resource access conflict. The Board, in Decision D 85-34, expressed doubt that a clear right of preferential access existed and concluded that it was in the public interest to seek a practical means to allow orderly, efficient, and economic development of both the coal and gas resources.

The Board granted Manalta a replacement licence to continue mining in accordance with the Base Plan subject to certain conditions. The Board, noting that the commencement of gas production was scheduled for November 1985, and as the anticipated life of the well was in question and may be minimal, concluded that production at the maximum rate feasible would reduce the potential for conflict and endorsed all reasonable effort to commence gas production as soon as possible.

2 ISSUES

During the proceeding both sets of participants, those interested in orderly development of the coal resources and those interested in production of the gas well, recognized that there would be interference between those operations irrespective of the proposals put forward. In the

end and predicated on APL's offer to absorb 50 per cent of the costs of whatever option was directed by the Board, there was virtually unanimous agreement that the optimum form of operation chosen would be one in which there would be minimum cost impacts and also the lowest practical level of interference of one operation upon the other. Additionally, all participants requested at the conclusion of the hearing that the Board, upon identifying the least-cost optimum course of action, give clear direction regarding approval of location and routing of pipeline facilities and, on Manalta's request of the Board, order a suspension or temporary abandonment of the well at the appropriate time. The options proposed for mining and pipeline routing are summarized in attached Tables 1 and 2, respectively.

Based on consideration of the foregoing, the Board concludes that the following are the key points to be addressed and in the sequence indicated.

- o What constitutes the major aspect of interference between the mining and the well production operation and what appears to be the most practical means of overcoming that interference?
- o What are the cost impacts involved in each of the options proposed?
- o Are there safety considerations that would render any one of the options unacceptable?
- o Which option provides the most reasonable opportunity for development of both resources?

3 MINIMUM PRACTICAL INTERFERENCE

3.1 Views of the Applicants

In suggesting that gas production and coal mining operations could not occur concurrently in the area of the well site, Manalta requested a well abandonment order from the Board once mining operations reach the immediate well area in 1990. Manalta's preference would then be to "mine through" the well area according to its Base Plan schedule. In the event that its request to mine through the well was not adopted by the Board, Manalta presented two alternatives. The first was to mine around the well site leaving a pillar of unrecovered coal. Because of increased mining costs and potential sterilization of 250 000 tonnes of coal, Manalta considered the "mine around" option to be unacceptable. Manalta's second option, one which it thought feasible, would be to terminate cuts at the east side of the well area, thereby leaving an estimated 750 000 tonnes of coal in the southwest corner of section 13 unmined. This second option, depending upon future economic evaluations, might allow for future return into the unmined area after depletion and abandonment of Chinook's well.

If, on the other hand, the Board determined that mining was to proceed through the Chinook well site, Manalta envisioned two potential options available to Chinook. Chinook could re-establish the well after mining and reclamation either by drilling a new directional well from mined-out lands or re-entering the existing well.

Manalta objected to the pipeline application because it would present an additional obstacle to the execution of its Base Plan. The preferred route as identified by Chinook would immediately interfere with mining operations and the alternative route would interfere in 1990.

Chinook's original position was that it should be allowed to produce gas concurrently with Manalta's coal production for an indefinite period. It would be flexible in the pipeline routing to accommodate mining operations. However, depending on future circumstances, Chinook acknowledged that the pipeline may have to be removed and re-routed by 1990 in order to accommodate mining operations. In addressing the alternatives as proposed by Manalta, Chinook was not prepared to commit to drilling a new directional well. The re-routing of pipelines and re-entry of the well after mining has passed through and beyond the well area would be economic decisions and could only be evaluated at future dates.

Chinook was unaware of Luscar's mining plans in the West Block of the Paintearth Mine but noted that it would consider altering or removing the pipeline when necessary so as not to interfere with those plans.

3.2 View of the Interveners

APL's basis for concern was that any additional mining costs would be passed on to APL by Manalta and eventually to APL's customers. As the pipeline would affect the progression of the mine, it would affect the supply and therefore the cost of coal to its Battle River electrical generating station. APL supported Manalta's application and the alternatives identified by Manalta for Chinook to drill a directional well or re-enter the existing well. Focusing its position on seeking the lowest combined costs option, APL indicated that it would be prepared to co-operate with Chinook to provide easements over any land in which APL owned the surface rights, that would be required by Chinook to construct a pipeline as requested.

Luscar presented a proposed mine plan for the West Block of its Paintearth Mine, which indicated that the optimum mine plan would be situated in the central third of the block, covering Chinook's preferred and alternative pipeline routes. If the pipeline was still in place and transporting gas in 1996, Luscar would be forced to design an alternative plan for mining to the north or south of the central third of the block. However, even if the pipeline were initially routed around the optimum mine plan area, it might later have to be re-routed to allow mining of the north or south portions of the West Block. Luscar would prefer that the pipeline, if approved, be removed and re-routed prior to commencement of its mining operations.

3.3 Views of the Board

It is evident that the lowest level of interference with the coal operations would be that in which no further activities would be undertaken respecting the gas well until coal mining operations had completely passed through the well site area. For this to occur the well would have to be suspended or temporarily abandoned below the level of the coal seam, mining operations allowed to proceed as if the well was not present, and later the well restored and the pipeline connected. In this case the well would not be placed on production until about 1992 or 1993. However, the pipeline connection to the 7-14 site apparently would have to be severed in 1996 to accommodate start-up of mining of the Paintearth West Block, so that the duration of operation of the well would only be 4 years before a major disruption would occur. This option, while being the minimum interference for coal mining, would result in an undesirable delay in well production, and even then might allow the well to produce only for a few short years when it would be subject to further interruption. Therefore the Board does not consider this possibility to be a suitable minimum practical interference option.

It is evident that the pipeline routing would result in unavoidable conflicts with mine operations in the Vesta Mine and adjustments to routing will be necessary to accommodate these operations. Recognizing this and having agreed to the concept of the lowest-cost option, Chinook indicated that it was prepared to be flexible in choosing a pipeline routing. As well, APL was prepared to provide easements to meet this objective. On that basis, the Board believes that the applied-for alternative route, as it may be modified by agreement of the parties, would be the most suitable. This route would provide a period of pipeline operation at least until the end of 1995 with possible interruptions depending on the mining option.

4 LOWEST COST

4.1 Views of the Applicants

Manalta stated that the least-cost approach should be adopted to minimize any incremental costs, and identified its mine-through approach as the most economic resolution. Manalta noted that significant deviations from the Base Plan to accommodate production of the 6 of 13 well would result in increased mining costs. Manalta noted that its preference to mine through the well would incur costs of $75 000 to $100 000 to temporarily suspend and later re-enter the well. If re-entry was unsuccessful, Manalta estimated that re-drilling the well would cost in the order of $300 000. Manalta's alternative option in avoiding the well would be to stop short of the well and leave some 750 000 tonnes of mineable coal unrecovered in the southwest corner of section 13. The incremental cost of this option was identified by Manalta to be $1.5 million, as deeper and therefore more expensive coal to the east would have to mined instead. Manalta also noted that the economics of coming back to mine this corner of section 13 at some later date was questionable. The remaining alternative that Manalta examined was to mine around the well site leaving a 270-metre-square pillar

of unrecovered coal around the well. The increased mining costs and the potential for sterilization of 250 000 tonnes of coal rendered the mine around option as the least desirable alternative.

Chinook doubted that the drilling of a directional well would be economically viable. In addition, it questioned the $1.5-million additional mining costs put forward by Manalta. Nevertheless it accepted that the lowest-cost option might be some combination of commencing well production now and, when needed, temporarily suspending and later re-entering the well, as well as removing and rebuilding pipelines when required to accommodate mining operations. Also, responding to the APL offer, Chinook was receptive to absorbing part of those costs.

4.2 Views of the Interveners

APL and Fording agreed with Manalta that the least-cost approach would be to suspend the well and mine through the well area.

Luscar noted that a pipeline in place in its West Block in 1996 would force it to go to an alternative mine plan that would result in higher costs because Luscar would have to mine less attractive holdings. The least-cost solution to Luscar would be for Chinook to immediately produce its well with a view to depleting the well before Luscar's mining operations begin in 1996.

4.3 Views of the Board

Table 1 is a summary of the comparative costs and impacts for each of the alternative operating strategies discussed at the hearing. Option 1 would require suspension or temporary abandonment and later re-entry of the well or, alternatively, abandonment of the well and later drilling of a new well. Additionally, this option would require at some point that the original pipeline, extending southward from the 6-13 well, be abandoned and shifted to a suitable route in the Manalta mined-out area. Total cost of these operations, including some additional costs for the mining operation, and the costs for the well suspension or temporary abandonment and subsequent operations range from $125 000 to $400 000. This option would permit production of the well from the end of 1988 to mid-1990 (1.5 years), suspension or temporary abandonment from mid-1990 to the end of 1992 (2.5 years), followed by resumption of production from 1993 to the end of 1995 (3 years) for a total of at least 4.5 years of well production.

Option 2, the one which Manalta proposed if the Board did not order the well to be suspended or temporarily abandoned, is that of altering the mine plan to exclude the southwest corner of section 13 of the Base Plan. This option would result in increased mining costs for the Base Plan of some $1.5 million. On the other hand, this option would allow the gas well to be connected by the southern pipeline alternative and allow continuous

operation of the gas well from the end of 1988 to the end of 1995 (7 years) without interruption. Accordingly, there would be no incremental costs involved for the gas well. This option, while being considerably more expensive than the mine-through option, would result in the approximately 750 000 tonnes of coal resources in the southwest corner of section 13 being deferred and mined later with the west half of section 12.

Option 3 would be to mine around the 6 of 13 well leaving a 270-metre-square pillar of unrecovered coal. This would result in increased operating costs due to extremely short cuts of the dragline on the southwest side of the pillar and likely sterilization of about 250 000 tonnes of coal. Manalta contended that costs for this mine-around option may be modestly less than Option 2, but Option 3 is not viable because of mining complications and potential for sterilization of coal. The Board believes that overall costs for this option, including costs for relocating pipelines and coal sterilization, would be close to Option 2. The gas well would be able to produce from the end of 1988 to mid-1990 at which point the pipeline would have to be abandoned and shifted from the unmined area over into a reclaimed mined area. Thus the gas well could be reconnected and could resume production from 1991 to the end of 1995 for an overall production period of 6.5 years.

5 SAFETY

5.1 Views of the Participants

Manalta noted that it could proceed with topsoil and subsoil salvage operations as scheduled up to a certain distance from the well. It would have to analyse the type of equipment to be used in the immediate well area and the operating procedures. Manalta agreed that the well could be produced up to the time that actual mining operations reached the well site, providing that mining operations were conducted in a safe manner. After suspension of the well and conclusion of mining in the well area, Manalta envisioned rebuilding the well by re-attaching joints of casing back to surface. A mound of earth would be built around the wellbore as ground restoration progressed to the original elevation surface. Manalta noted that there would be little subsidence in the area surrounding the wellbore as heavy mobile equipment would be used to build the mound. Based on its geotechnical assessments and safety concerns, the pipeline would have to be located at least 90 metres from the mining operations.

5.2 Views of the Board

Because of the nature of operations, careful attention would have to be given to geotechnical factors which come into play when the mining operation is in proximity to the well and pipeline. Clearly the safest option for protection of the well casing would be either to by-pass mining in the southwest corner of section 13 or to provide for a safety pillar of

some 270 metres square around the 6-13 well. The option of suspending or temporarily abandoning the well and mining through introduces some well safety considerations that would require careful procedures. The Board would not expect subsidence to be a problem given that heavy mobile equipment would be used in reclaiming the well area. Special procedures to rebuild the well and reclaim the immediate well area would have to be developed by Manalta and Chinook and ultimately approved by the Board. Regarding pipelines, precautions would be required to ensure that shifting the pipeline into previously disturbed land would not result in a risk to the pipeline from soil subsidence. The most critical aspect of safety is that of avoiding situations where heavy equipment operators might inadvertently damage either the wellhead or pipeline during soil stripping or mining operations.

6 OPPORTUNITY FOR DEVELOPMENT OF EACH RESOURCE

6.1 Views of the Applicants

Manalta, following its preferred mine-through strategy, put forward two mine plan schedules. Following the Base Plan schedule, the well would be suspended by mid-1990 with the well being re-established in 1993. This schedule would allow an initial 1.5 years of gas production followed by a 2.5-year suspended period. The second schedule, involving acceleration of the Base Plan, would require suspension of the well in mid-1989 with the well being re-established at the end of 1990. This option would allow 6 months of initial gas production followed by a 1.5-year suspended period.

Given a choice between the two mine schedules proposed by Manalta, Chinook's preference would be the immediate commencement of well production followed by suspension of the well from mid-1990 until the end of 1992. The 1.5-year period of initial production would allow Chinook to conduct reservoir performance studies so as to better define likely recoverable gas reserves. Chinook would then be in a better position to evaluate the economics of re-entering the well after 1992, compared to the case where only 6 months of production was obtainable. This interim production period would also enable Chinook to initially fulfil a gas sales contract and gathering and processing agreements with Esso and Newalta. In a related matter Chinook was concerned that suspension or temporary abandonment of the well, even if the well were to be later re-entered, might automatically trigger termination of its petroleum and natural gas lease.

6.2 Views of the Interveners

APL and Fording supported Manalta's proposals. Luscar would prefer that any pipeline in its West Block be abandoned or removed by 1996 in order that it could produce its resource. The Haeberles could not address the effect of a temporary suspension or permanent abandonment of the well on

the possibility of termination of their lease with Chinook. If, as a result, the lease did expire, they noted that it might not be economical for another company to re-drill or re-enter the well to recover the remaining gas reserves.

6.3 Views of the Board

The optimum choice for development should provide for the reasonable earliest commencement of gas well production operations and the longest reasonable duration of those operations. The mine-through option offers the optimum possibility of meeting these objectives as it involves only minor mining operations adjustments and allows a reasonable period of well production before interference with the planned Luscar operations would occur. Indeed, an improvement to the mine-through option would be to shorten the period of well suspension or temporary abandonment to perhaps no more than a year.

The Board considers the question of the continuance of the petroleum lease agreement to be a legal matter and not within the jurisdiction of the Board. In any case, whether or not this lease would terminate is a business risk that would not influence the Board's decision.

7 DECISION

The Board has decided to grant Chinook's Application 880920 with the location of the pipeline to be that location identified as the alternative route. The Board would accept modifications to the alternative route as agreed upon by Manalta, Chinook, APL, and Luscar. The pipeline permit will be issued upon appropriate licensing of the pipeline from 7 of 14 to the gas plant for the transportation of gas containing hydrogen sulphide.

The Board concludes that Option 1 (as noted in Table 1) is the most suitable strategy for accommodating the various interests. Accordingly, regarding Manalta's Application 880499, the Board directs that arrangements be made to suspend or temporarily abandon the CHINOOK RED WILLOW 6-13-40-16 well on or about 1 July 1990 or such other date as later directed by the Board. The suspension or temporary abandonment shall be effected in a suitable manner at a depth below the base of the coal seam to facilitate mining of coal through the well site.

To ensure that properly co-ordinated and safe operations are conducted by Manalta and Chinook on a continuing basis, the Board will establish an operating committee. For convenience, the committee will be called the Manalta/Chinook Committee. The committee will be chaired by an ERCB representative and will meet at the request of the chairman when any concerns, safety matters, or scheduling difficulties arise. Chinook, Manalta, APL, and Luscar will each be given the opportunity to provide a committee member.

In accordance with the foregoing, and subject to future advice from the Manalta/Chinook Committee, the Board informs the participants of its expectations concerning schedules and activities that may be undertaken by Chinook and Manalta:

1. Chinook would be expected to commence production from the 6 of 13 well as soon as possible.

2. Construction of the Chinook pipeline should commence as soon as possible after the Board permit is issued. The route will be the alternative route as proposed or such other route as is acceptable to Manalta, Chinook, APL, and Luscar. To allow continuation of mining operations, a portion of the pipeline will be abandoned and re-routed simultaneously with the suspension or temporary abandonment of the 6 of 13 well. For those purposes Chinook will submit the necessary applications to the ERCB's Pipeline Department.

3. The 6 of 13 well will be suspended or temporarily abandoned by about 1 July 1990.

4. The operations and procedures for suspending or temporarily abandoning the well with setting of appropriate bridge plugs and cement will be subject to review and approval of the ERCB's Drilling and Production Department and Coal Department after receiving advice from the Manalta/Chinook Committee.

5. Manalta will mine through the well area in accordance with its Base Plan and by 1 January 1993, or earlier if feasible, complete reclamation operations so as to permit Chinook to re-enter the existing well or drill a replacement well.

6. For the purposes of clauses 1 to 5, the Board may alter the dates specified upon advice from the Manalta/Chinook Committee.

7. In accordance with the Board-directed program as set out above, and the undertakings by APL respecting cost sharing, the Board believes it appropriate that certain costs should be shared and directs the allocation of costs as follows:

    a) The costs associated with the Board-directed well suspension or temporary abandonment operations, rebuilding of surface casing, re-entry of the well and reinstallation of the wellhead equipment, or re-drilling of the well shall be borne equally by Manalta and Chinook.

b) Manalta shall be solely responsible for all costs associated with removal of the well casings to the base of the coal seam and all overburden backfilling and reclamation activities.

c) The costs associated with the abandonment, replacement, relocation, and reconnection of the pipeline shall be borne equally by Manalta and Chinook.

DATED at Calgary, Alberta, on 16 November 1988.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

E. J. Morin, P.Eng.
Board Member

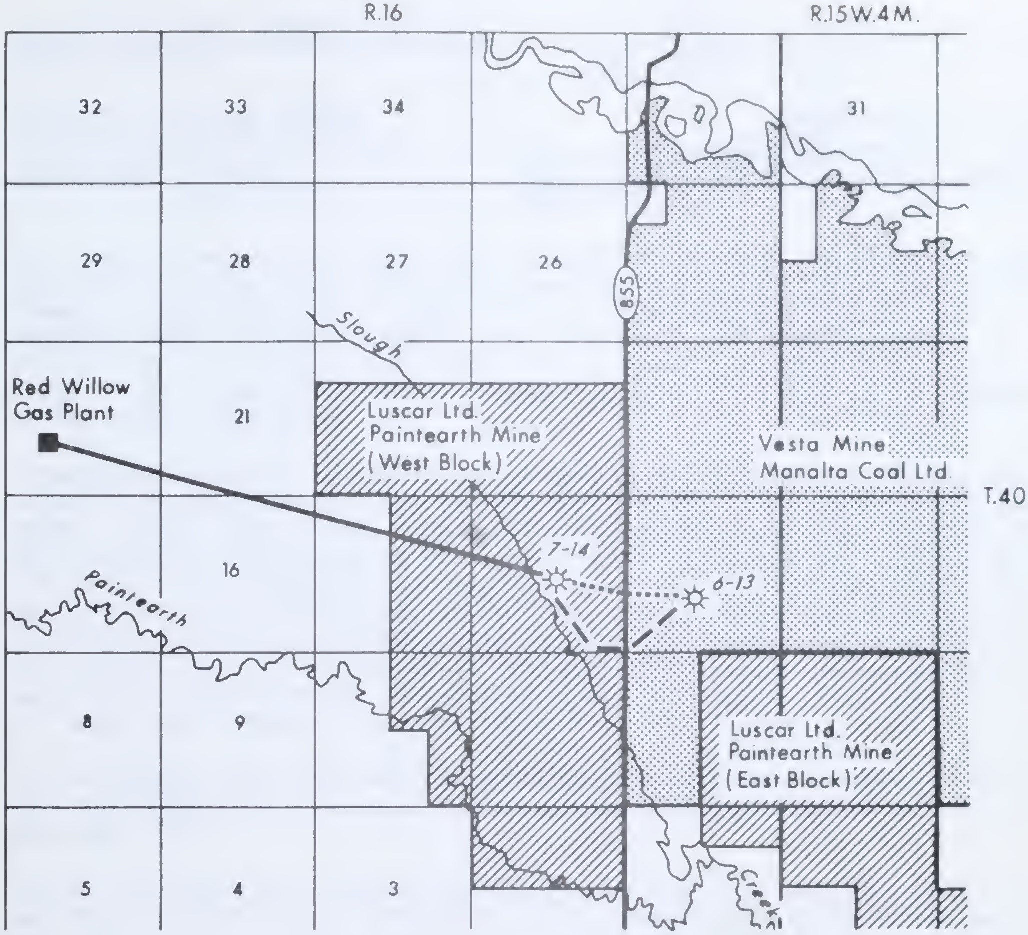
R. G. Evans, P.Eng., Acting Board Member,
concurs with the contents and with
the issuing of this report.

TABLE 1 SUMMARY OF RESOURCE DEPLETION OPTIONS

Strategy	Option	Impact on Resource Operations		Summary of Estimated Costs (Mine, Well & P/L)	Participant Views	ERCB Conclusion
		Coal	Gas			
Mine through 6 of 13 well.	1	Nil.	Produce end 1988 to mid-1990 (1.5 year). Suspend mid-1990 to end 1992 (2.5 years). Resume production 1993 to end 1995 3 years). Total 4.5 years. $50 000 P/L relocation cost, $75 000 to $100 000 suspension and re-entry cost, or $300 000 re-drill new well.	$125 000 to $400 000.	Manalta's preferred option.	Least-cost option. Approved.
By-pass mining of southwest quarter of section 13.	2	Mining of 750 000 tonnes deferred.	Well produce end 1988 to end 1995 (7 years).	$1.5 million.	Manalta's alternative. Fording loss of revenue $1.5 million to $2 million.	More expensive than mine-through option. Mining of coal deferred.
Mine around 6 of 13 (pillar).	3	Sterilization of 250 000 tonnes.	Produce end 1988 to end 1995 with short interruption for P/L shift ($50 000) to allow mining around pillar (6.5 years).	Less than Option 2.	Manalta - not a viable alternative. Fording's loss of revenue for 250 000 tonnes of coal.	Mining complications. Potential for coal sterilization.

TABLE 2 SUMMARY OF PIPELINE ROUTE OPTIONS

Strategy	Impact on Resource Operations: Coal	Impact on Resource Operations: Gas	Participant Views	ERCB Conclusion
Preferred P/L route:				
P/L directly west; 6 of 13 well to 7-14.	Direct interference with mine operations by 1988/89.	a) Install late 1988.	Chinook agreeable to any route. Want to produce well immediately.	a) Immediate interference between mine and well operation. Impractical, costly, safety problems. Denied.
		b) Defer installation to late 1992 to allow completion of mining and reclamation.		b) Useful period of P/L 1993 to end 1995 (3 years).
Alternative P/L route:				
a) From 6 of 13 well to south boundary of section 13.	a) Would not interfere now but in 1990.	a) Would allow operations of well at least until end of 1995 with possible interruptions depending on mining option.	Chinook agreeable to this route. Manalta wants to avoid future interference with mine. Luscar does not want P/L in Paintearth West Block in 1996. APL prepared to give P/L ROW easement for least-cost route.	a) Optimum route chosen to provide for least interference. Well could produce from late 1988 to end of 1995, uninterrupted for the by-pass mining option, with short interruption for mine-around option, and 2.5-year interruption (mid-1990 to end of 1992) for mine-through option.
b) From south boundary of section 13, directly west into section 14, then north-west to 7-14.	b) Directly interferes with Luscar's mine plan in 1996.	b) Interruption of P/L operation in late 1995.		b) Situation in 1996 uncertain. Well production may be near termination. Grant alternative route through southeast quarter of section 14 to 7-14 well.



Existing Pipeline
Alternative Pipeline Route
Preferred Pipeline Route

MANALTA COAL LTD. AND LUSCAR LTD. MINE PERMIT AREAS
Applications No. 880499 and 880920
Battle River Area

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

WESTHILL RESOURCES LIMITED
APPLICATION FOR WELL LICENCES
ACHESON EAST FIELD

Interim Decision D 88-15
Applications 880984, 880985.
880986, and 880988

At a public hearing on 20 July 1988 in Edmonton, Alberta, the Energy Resources Conservation Board (Board) heard applications by Westhill Resources Limited (Westhill) for licences for wells to be known as WESTHILL ACHE 6-9-53-25, WESTHILL ACHE 8-9-53-25, WESTHILL ACHE 14-9-53-25, and WESTHILL ACHE 12-10-53-25, all to be drilled from surface location in LS 10-9-53-25 W4M. This location is at 114 Avenue and 174 Street, an industrial area in the western part of the city of Edmonton.

A number of owners of buildings and/or land in the vicinity of the proposed wells filed interventions opposing the applications. The owners of the mineral rights for the Basal Quartz formation to be tested by the proposed wells filed an intervention in support of the applications. The applicant expects to find oil, but for emergency planning purposes has considered the possibility of encountering gas. Production, whether oil, gas, or both, may contain small quantities of hydrogen sulphide. The opposing interventions were based primarily on concerns that the appearance of the proposed wells and the possibility of unpleasant odors would have an adverse effect on property development and value, and might pose a risk to existing facilities.

At the hearing, the applicant requested an early decision so that it could take full advantage of a government incentive that will be reduced at the end of September 1988.

Having considered the evidence presented, the Board has concluded that the applications can be approved subject to the undertakings given at the hearing. Special conditions will be applied to the testing of productive capability and, if the wells are successful, to regular production operations. Since approval of the production facilities will require further applications to the Board, these special conditions need not be detailed here. However, the Board plans to require gathering and incineration of all hydrocarbon vapors associated with the produced oil from any temporary or permanent production facilities.

Having decided to approve these applications, the Board is issuing this interim decision so that the applicant will not be unduly penalized because of the length of time required for preparing a formal decision report.

Accordingly the Board will proceed immediately to issue the well licences for the proposed wells.

Dated at Calgary, Alberta on 16 September 1988.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince, Ph.D.
Board Member

E. J. Morin, P.Eng.
Board Member

N. G. Berndtsson, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

WESTHILL RESOURCES
APPLICATION FOR WELL LICENCES
ACHESON EAST FIELD

Decision D 88-15
Applications 880984,880985, 880986, and 880988

1 INTRODUCTION

1.1 Applications and Interventions

Westhill Resources Limited (Westhill) applied to the Energy Resources Conservation Board (the Board), pursuant to section 2.020 of the Oil and Gas Conservation Regulations (the Regulations), for licences to drill wells to be known as WESTHILL ACHE 6-9-53-25, WESTHILL ACHE 8-9-53-25, WESTHILL ACHE 14-9-53-25, and WESTHILL ACHE 12-10-53-25 (the proposed wells) to obtain production from the Basal Quartz Formation. All of the proposed wells would be directionally drilled from a common surface location in legal subdivision 10 of section 9, township 53, range 25, west of the 4th meridian (the proposed surface location).

Interventions opposing the applications were filed by R. M. Curtis on behalf of Homestead Holdings Ltd., The Jasper Printing Group Ltd., Lehndorff Property Management Limited, Eleventh Properties Ltd., and Top Discount Stores Ltd. In addition, at the hearing, Mr. R. Bosetti, representing Continental Can Canada Inc., came forward to participate in the proceeding.

A written submission in favour of the applications was filed by R. A. Philion on behalf of Mr. and Mrs. Paul Garneau and Mr. Rudolphe Garneau, who are the mineral owners in the northeast quarter of section 9, township 53, range 25, west of the 4th meridian.

1.2 Hearing

A public hearing of the applications was held at the Mayfield Inn in Edmonton, Alberta, on 20 July 1988, before Board Members J. P. Prince, Ph.D., E. J. Morin, P.Eng., and Acting Board Member N. G. Berndtsson, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Westhill Resources Limited (Westhill) Scott Miller	J. S. Rogers W. Rogers J. K. Farries, P.Eng.
Homestead Holdings Ltd. R. M. Curtis	
The Jasper Printing Group Ltd. R. M. Curtis	
Lehndorff Property Management Limited (Lehndorff) R. M. Curtis	Clive Townley
Eleventh Properties Ltd. R. M. Curtis	
Top Discount Stores Ltd. R. M. Curtis	
Continental Can Canada Inc. (Continental Can) R. M. Curtis	R. Bosetti
Mr. & Mrs. Paul Garneau and Mr. Rudolphe Garneau R. A. Philion	Armande Garneau
Energy Resources Conservation Board staff M. J. Bruni C. S. Richardson	

1.3 Interim Decision

An interim decision approving the applications was issued by the Board on 16 September 1988. A copy of Interim Decision D 88-15 is attached.

1.4 Background

The surface location of the proposed wells would be adjacent to the eastern boundary of the Acheson East Field, which is defined by Board Order F 4490. Oil production in this area is from the Lower Mannville Formation. Fluids produced from that formation in this area contain small amounts of hydrogen sulphide (H_2S).

The surface location for the proposed wells is within the boundaries of the City of Edmonton (the City). The location is contiguous to the north side of the proposed location of 114 Avenue and the west side of the proposed location of 174 Street. The location is adjacent to several privately owned lots that are included by the City in a heavy industrial zone.

Prior to submitting well licence applications to the Board, Westhill discussed its proposed surface location for the wells with the City and obtained conditional approval to proceed with its plans for the development. The proposed wells and surface location satisfied the setback requirements as set out in the Policy Guidelines for the Integration of Resource Operations and Urban Development (the Policy Guidelines) adopted by the City. In its consultation with the City, Westhill chose a common, centralized surface location (Figure 1) in an attempt to minimize surface impact and avoid the sterilization of development on adjacent lands.

The interventions filed with the Board were from property owners and businesses located close to the proposed surface location. The interveners cited several fundamental reasons supporting their objection to the wells. These included a negative impact on the aesthetics of the area, and safety and other concerns arising from the possible release of H_2S and mercaptans. These fundamental concerns, whether real or perceived, were said to have an adverse effect on the potential to develop neighbouring lands and would, therefore, significantly reduce the value of those lands. The interveners contended that, because of these adverse effects, the drilling of wells should not be allowed within the city limits. The interveners argued that the applicant had provided insufficient justification for drilling such wells.

In 1983, the Board held a public Inquiry, with respect to the West Edmonton area, that considered representations from mineral owners, oil and gas operators, surface owners, and urban developers. The results of the Inquiry were set out in ERCB Inquiry Report D 83-F, entitled <u>Resource Development/Urban Development: West Edmonton Area</u> (the Inquiry Report) and published in July 1983. "The intent of the Inquiry was to determine whether co-existent development of both the surface and subsurface resources of the Inquiry area is feasible, and if it is, what guidelines and legislative changes would provide a framework for co-existence." (p. 2)

The Board concluded that concurrent development was possible and made a number of recommendations intended to facilitate the development. One recommendation resulted in the formation of the West Edmonton Liaison Committee. The Committee consists of representatives from the Energy Resources Conservation Board, the City of Edmonton, the Edmonton Municipal Regional Planning Commission, and Alberta Environment. The Committee reviews development applications in an attempt to ensure that resource and urban plans do not conflict. The well licence applications that are the subject of this decision report were referred to the Committee. The Committee did not subsequently file any concerns with the hearing.

The surface location for the proposed wells is approximately 1 kilometre east of the area considered in the Inquiry Report. During the hearing, the interveners questioned the applicability of the Inquiry Report to the location. They argued that this location was outside of the Inquiry Report's defined area, so the guidelines established in the report for the co-operative development of natural resources and of urban activities should not be applied in this case.

The Board believes that although the proposed location is outside of the defined Inquiry area, this does not preclude the application of those guidelines to this location. Although the Inquiry Report clearly stated that future applications would be decided on their own merits, the Board intended the Inquiry Report to be used as a guide for the concurrent development of urban facilities and natural resources in the West Edmonton area. The West Edmonton Liaison Committee, established as a result of the Inquiry, reviews all applications for oil and gas development in the West Edmonton area, even those not located in the specific regions defined by Inquiry Report D 83-F.

2 ISSUES

The Board considers the issues with regard to these applications to be

- the purpose and need for the wells,
- the conflict of land use and the surface location of the wells,
- the impact of the wells, and
- the safety of the public.

3 PURPOSE AND NEED FOR THE WELLS

3.1 Views of the Applicant

Westhill submitted that its petroleum and natural gas leases and options to lease give it the right to explore for and develop the reserves that it believes underlie the south half of section 9, the northwest quarter of section 9, and the northwest quarter of section 10, all located in township 53, range 25, west of the 4th meridian. The proposed wells, if successful, would extend the boundaries of the Acheson East Blairmore F Pool (Board Order G 4922) north from section 4, township 53, range 25, west of the 4th meridian, where the wells, WESTHILL ACHE 11-4-53-25 and PEYTO WINTERBURN 6-4-53-25, produce oil from this pool. Westhill submitted that the proposed wells would obtain a combined production of approximately 31.8 cubic metres of oil per day and estimated the extension would add a total of 159 000 cubic metres of recoverable oil to the Province's reserves. Westhill further submitted that the wells would fulfil contractual obligations to its lessors and provide benefits including a 10 per cent mineral tax to the Province of Alberta, tax revenue to the City, employment opportunities for local residents, and royalties to be paid to the mineral owners.

3.2 Views of the Interveners

The interveners did not dispute the bottom-hole locations of the proposed wells, Westhill's geological interpretation, or Westhill's right to recover the reserves. They contended, however, that this type of surface development would generate the least possible amount of tax dollars to the City and would reduce the value of neighbouring lands to the detriment of the owners of those lands and the City. They submitted that no oil or gas drilling should be allowed within the city limits.

Mrs. Armande Garneau stated that as the mineral owners of the northeast quarter of section 9, Rudolphe and Paul Garneau had entered into a lease agreement with Westhill and were in support of the applications for well licences.

3.3 Views of the Board

The Board accepts that Westhill, through leases and options to lease, has the right to explore for and develop the reserves that may underlie the south half and northwest quarter of section 9 and the northwest quarter of section 10. Further, the wells are needed to determine whether or not economically recoverable reserves exist at that location. Should such reserves be found, benefits would accrue to the Province through mineral taxes, to the City through property taxes, to the mineral owners through royalties, to local residents through increased employment, and to consumers through increased supplies of oil. The Board also accepts Westhill's geological interpretations and estimates on production and total recoverable oil. The Board would, therefore, be prepared to approve the drilling of the wells, provided that the other issues raised by the interveners are considered appropriately and either resolved or judged to be inadequate justification to deny the application.

4 OTHER ISSUES (CONFLICT, IMPACT, AND SAFETY)

4.1 Views of the Applicant

With respect to choosing a surface location for the proposed wells, Westhill submitted that it has agreed to comply with the conditions of its approval from the City and that its proposed surface location adheres to the recommendations of the Inquiry Report and the Policy Guidelines. As a result, Westhill believes that the proposed surface location will ensure the least possible conflict with adjacent land uses. Westhill further stated that this location was agreed to by the surface owner, Barbican Developments Ltd., and that Westhill had entered into a lease agreement with the surface owner giving Westhill the right to enter the land surface to explore for the underlying minerals.

Westhill considered the impacts to adjacent lands would be minimal during the drilling and production phases of the proposed wells. It submitted that the standards imposed upon the facility by the City of Edmonton Municipal Planning Commission would classify the facility as light industrial when in fact this area has been classed as heavy industrial. Westhill stated that its facility would exceed the standards of the area, thus minimizing any negative aesthetic impacts. In its submission, Westhill illustrated that the 50-metre development setbacks as established in the Policy Guidelines and Inquiry Report, when applied to the proposed wells, would not restrict development on any of the lands adjacent to the proposed location. Further measures which Westhill proposed to reduce impacts from the proposed wells included electrification of motors to reduce noise levels, landscaping, mesh fencing, and incineration rather than flaring to reduce visual impacts.

With respect to public safety, Westhill stated that there would be no risk to the health or safety of the public from the proposed wells. In its submission, Westhill calculated the maximum potential H_2S release rate to be 0.0014 cubic metres per second, placing these wells well below the threshold value of 0.01 cubic metres per second that would classify the wells as a Level 1 sour facility. Westhill contended that, based on these values, an emergency response plan is not required for the drilling or production phases of these wells. Moreover, to eliminate odours, Westhill stated that the facility would be a closed production system where all vapours would be contained and incinerated. The facility would also be fenced to keep out unauthorized people, and there would be 24-hour availability of personnel to the site in the event of an emergency.

4.2 Views of the Interveners

The interveners contended that significant conflicts would exist between the use of the land at the proposed location for the wells, and current and future uses of the adjacent lands. Lehndorff submitted that the development of a multi-well battery at this location would preclude its purchase of adjoining lands to the south because of its inability to lease those lands if an oil facility were present. Lehndorff stated that a multi-well battery would be perceived by its prospective lessees as potentially negative to industrial operations and might cause prospective lessees to locate in a more industrially homogeneous and sterile environment. Lehndorff acknowledged that this negative impact is more perceptual than actual, but that means mitigative measures are not likely to solve the problem.

Lehndorff further contended that the taxes generated for the City by its proposed development of the adjoining lands would greatly exceed the taxes generated by the proposed wells and facilities. Also, adjacent land values would be greatly diminished with the presence of an oil facility.

Continental Can submitted that its present facility located adjacent to the proposed surface location would be put at risk by the drilling and operation of the proposed wells. It submitted that any odours emanating from such an oil facility could become entrained within the porous lacquer used to coat the inside of the cans it manufactures. It stated that this lacquer is highly susceptible to absorption of odours and, in particular, those odours containing sulphur compounds. In addition, this absorbed odour would create an off flavour to any products that were contained within the can, thus rendering the can useless. Continental Can stated that up to 32 million cans may be stored at its facility, and the value of those cans would be approximately 4 million dollars. Continental Can did not express concerns related to aesthetic impact, public safety, or conflict of land use.

The interveners stated that this area is in the city proper and suffers from the encroachment of the resource developers. The interveners suggested that oil operations should not be allowed within an urban setting and that the benefits that may accrue to the mineral owners and Province of Alberta do not outweigh the adverse impacts upon the landowners and industrial operations adjacent to the proposed wells.

The interveners contended that, considering the location of the proposed wells in a major urban centre, the Board should require Westhill to prepare an emergency response plan to address the possibility of a major release of sour gas. They submitted that Westhill is not experienced in dealing with sour gas and that public safety would be compromised by the absence of an emergency response plan during the drilling and production of the proposed wells. They did acknowledge, however, that the wells were not likely to encounter hydrogen sulphide in any substantial quantity.

4.3 Views of the Board

With regard to conflict between current and future land use and the development of the energy resources, the Board must consider the rights of the parties involved:

- the rights of the applicant to explore for and recover the minerals that it believes underlie the lands,

- the rights of the mineral owners,

- the rights of the landowners and existing firms in the vicinity of the proposed wells,

- the rights of the surface owner, and

- the rights of the public in the Province of Alberta.

The Board notes that there was no objection to Westhill's right to explore for its minerals, that no specific alternate surface location was suggested for the wells to alleviate perceived adverse impacts or conflicts of land use, and that Westhill's geologic interpretation was not disputed.

With regard to the rights of the adjacent landowners and firms, the Board notes that Westhill has received approval from the City and has agreed to comply with the conditions imposed on it by the City in order to drill and operate its facility within the city boundaries. Also, the Board accepts that the 50-metre development setback from the wells, as established in the Inquiry Report and Policy Guidelines, does not intersect any adjoining lands and thus does not preclude current or future development on those lands. It is noted that the City provides for heavy industrial development in this area and that the proposed well facility will conform to that zoning and, in fact, would also conform to light industrial zoning, should that be imposed in future.

With respect to right of access to the land surface, the Board notes that Westhill has entered into a lease agreement with the surface owner, Barbican Developments Ltd., and that the surface owner has agreed to the proposed well locations.

In consideration of the rights of the Province of Alberta, the City, and the mineral owners, the Board accepts that, should the well be successful, there would be taxes payable to the City, a 10 per cent mineral tax would be payable to the Province of Alberta, and the freehold mineral owners would obtain a royalty from production from the proposed wells. Although the maximum reduction in property taxes that would be borne by the City if the wells did result in no further urban development in the vicinity might be significant, no evidence was presented as to what that reduction would be, and no evidence was presented to support the position that urban development would be halted by the drilling of these wells. The Board believes that even if some businesses are discouraged from neighbouring locations because of the wells (and that result is by no means certain), other businesses, less sensitive to the possible effects of emissions from the wells, would locate there. In that event, which was acknowledged by Lenndorff, tax revenues to the City would probably not be affected. Moreover, no evidence was presented at the hearing to support the contention that the value of neighbouring property would be reduced because of the existence of wells. Should the wells be unsuccessful, there would be no adverse effects on the surrounding community but useful information about the extent of this Acheson oil pool would be gained.

The Board believes that the effects of the proposed wells and surface location on the adjacent landowners and industrial operations would be minimal. The perceived impact on the development potential of the adjacent lands would be mitigated by Westhill's conformance to the

standards imposed by the City, the Inquiry Report, and the Oil and Gas Conservation Regulations. The Board also notes that Westhill proposes electrification to reduce noise, a closed vapour recovery system to reduce odours, incineration to eliminate the visual impact of a flare, painting compatible with the surrounding industries, landscaping to reduce negative aesthetic impacts, and adequate fencing to screen the facility and prevent unauthorized entry.

While the Board recognizes the potential for a release of odours from the proposed facility and the possible effect of those odours on the Continental Can operations, the Board is satisfied that because of the low levels of H_2S associated with the Basal Quartz Formation in this area, and the incineration and closed vapour recovery system proposed by Westhill, the possibility of a release of vapours will be minimal. Moreover, Continental Can acknowledges that about 80 per cent of the time the prevailing winds were from the west and would, therefore, carry any emissions from the well away from its location. While there may be a risk to Continental Can associated with the drilling and operation of the proposed wells, the Board sees that risk to be very small and believes that it should not preclude the drilling of the wells. The Board notes that Continental Can did not provide any evidence related either to the risk of emissions or the possible effect of any emissions on their operations. And finally, the Board believes that in the event of loss attributable to the proposed wells, Continental Can may have a remedy in Civil Law.

With regard to safety, the Board is satisfied that, given the small amounts of H_2S gas likely to be encountered and the low formation pressures associated with the Basal Quartz Formation in the Acheson East area, Westhill's proposed safety measures for the drilling and production operations will ensure that public safety is not compromised. The Board accepts Westhill's calculated maximum potential H_2S release rates and concurs with Westhill's submission that an emergency response plan is not required for the drilling and operation of the proposed wells. In the unlikely event that significant amounts of H_2S are encountered, Westhill stated that it would not proceed with the wells. The Board notes that Westhill proposes closed vapour recovery, incineration, fencing of the lease boundary, and 24-hour availability of staff to further ensure public safety.

4 DECISION

The Board has carefully considered the evidence and the views of the interveners and the applicant. The Board believes that there is a need for the wells and that the wells can be drilled and operated with little impact or conflict with the adjacent landowners and industrial operators. The Board concludes that any adverse impact will be minimized by the measures Westhill has agreed to implement and that the need for the wells outweighs those impacts. The Board also believes

that the wells can be drilled without compromise to public safety and notes that Westhill will implement measures to ensure public safety. The Board has therefore approved the applications, subject to all of the undertakings given by the applicant at the hearing and to the following specific conditions:

1. The well site and production facilities shall be enclosed by wire mesh fencing, including locked gates, in accordance with sections 8.170 and 8.180 of the Regulations.

2. All pump motors shall be electrically driven.

The Board further believes that special conditions should be applied to the testing of productive capability and, if the wells are successful, to regular production operations. Approval of the production facilities will require further applications to the Board, at which time these special conditions will be set out in detail. The Board plans to require gathering and incineration of all hydrocarbon vapours associated with the produced oil from any temporary or permanent production facilities.

DATED at Calgary, Alberta, on 8 November 1988.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince, Ph.D.
Board Member

E. J. Morin, P.Eng.
Board Member

N. G. Berndtsson, P.Eng.
Acting Board Member

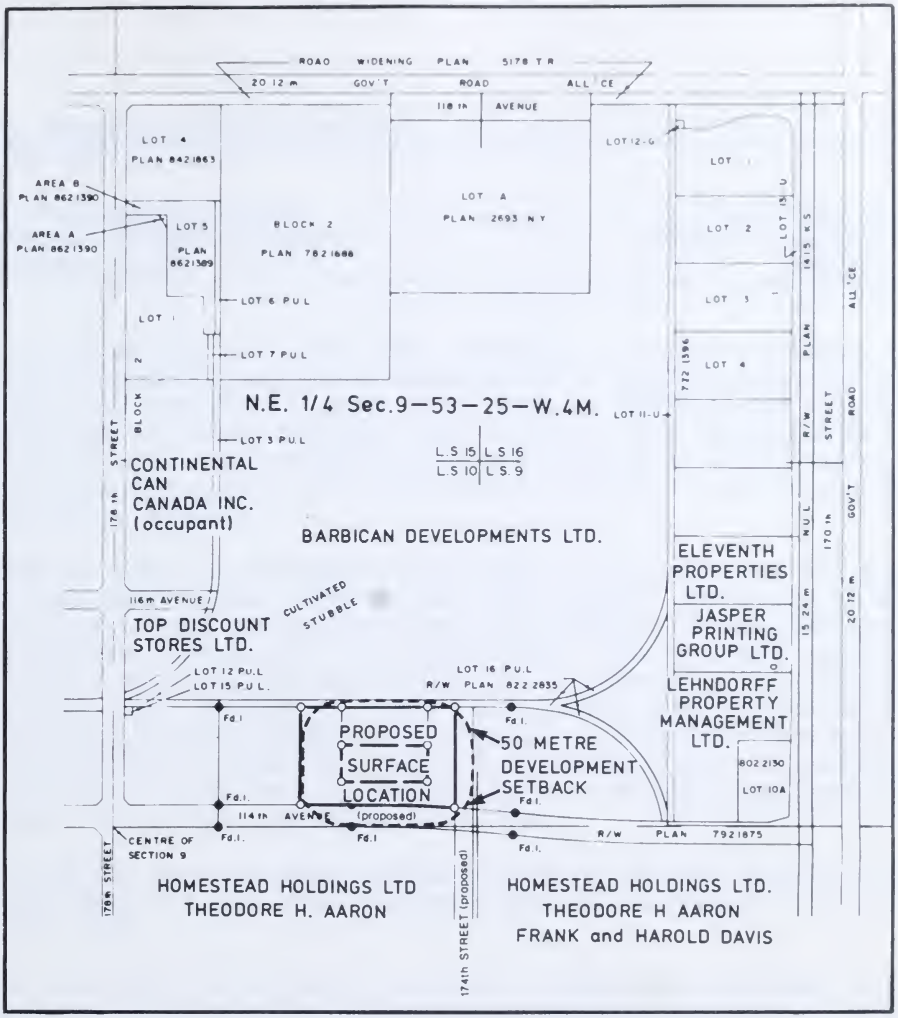


FIGURE 1: PROPOSED SURFACE LOCATION OF MULTI—WELL PAD
LSD 10 SECTION 9 TOWNSHIP 53 RANGE 25 WEST 4th
Applications No. 880984,880985,880986,880988
Westhill Resources Limited

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

WESTHILL RESOURCES LIMITED	Interim Decision D 88-15
APPLICATION FOR WELL LICENCES	Applications 880984, 880985.
ACHESON EAST FIELD	880986, and 880988

At a public hearing on 20 Julv 1988 in Edmonton, Alberta. the Energy Resources Conservation Board (Board) heard applications by Westhill Resources Limited (Westhill) for licences for wells to be known as WESTHILL ACHE 6-9-53-25, WESTHILL ACHE 8-9-53-25, WESTHILL ACHE 14-9-53-25, and WESTHILL ACHE 12-10-53-25, all to be drilled from surface location in LS 10-9-53-25 W4M. This location is at 114 Avenue and 174 Street, an industrial area in the western part of the city of Edmonton.

A number of owners of buildings and/or land in the vicinity of the proposed wells filed interventions opposing the applications. The owners of the mineral rights for the Basal Quartz formation to be tested by the proposed wells filed an intervention in support of the applications. The applicant expects to find oil, but for emergency planning purposes has considered the possibility of encountering gas. Production, whether oil, gas, or both, may contain small quantities of hydrogen sulphide. The opposing interventions were based primarily on concerns that the appearance of the proposed wells and the possibility of unpleasant odors would have an adverse effect on property development and value, and might pose a risk to existing facilities.

At the hearing, the applicant requested an early decision so that it could take full advantage of a government incentive that will be reduced at the end of September 1988.

Having considered the evidence presented, the Board has concluded that the applications can be approved subject to the undertakings given at the hearing. Special conditions will be applied to the testing of productive capability and, if the wells are successful, to regular production operations. Since approval of the production facilities will require further applications to the Board, these special conditions need not be detailed here. However, the Board plans to require gathering and incineration of all hydrocarbon vapors associated with the produced oil from any temporary or permanent production facilities.

Having decided to approve these applications, the Board is issuing this interim decision so that the applicant will not be unduly penalized because of the length of time required for preparing a formal decision report.

Accordingly the Board will proceed immediately to issue the well licences for the proposed wells.

Dated at Calgary, Alberta on 16 September 1988.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince, Ph.D.
Board Member

E. J. Morin, P.Eng.
Board Member

N. G. Berndtsson, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SHELL CANADA LIMITED
APPLICATION FOR A WELL LICENCE
WATERTON FIELD

Decision Report D 88-16
Application 880557

1 INTRODUCTION

1.1 Application

Shell Canada Limited (Shell) applied, pursuant to Part 6 of the Oil and Gas Conservation Act, for a licence to drill a well from a surface location in legal subdivision 2 of section 25, township 4, range 2, west of the 5th meridian, to a projected bottom-hole location in legal subdivision 6 of section 30, township 4, range 1, west of the 5th meridian. The proposed well, to be known as SHELL WATERTON 6-30-4-1 (the 6-30 well) would be for the purpose of obtaining gas production from the Mount Head and/or Livingstone Formation.

The location of the proposed well and pertinent geographical features of the surrounding area are shown in Figure 1.

1.2 Area of Application

The proposed well would be drilled in the northern portion of the Energy Resources Conservation Board (the Board) defined Waterton Field at a site approximately 20 kilometres (km) southwest of the town of Pincher Creek and approximately 16 km north of Waterton Lakes National Park.

The proposed well surface site, as illustrated in Figure 2, would be located on the eastern edge of the upper Whitney Creek drainage basin. The sub-alpine basin is surrounded by mountain terrain with Prairie Bluff on its east and Victoria Peak on its south. As outlined in Section 1.3 of this report, in the upper Whitney Creek basin, Zone 5 multi-use lands rise from the valley floor to adjoin Zone 1 prime protection land where preservation of sensitive terrain and aesthetic resources is given high priority. The proposed access road to the well site would start at the well, SHELL 13 WATERTON 10-26-4-2, cross a bridge which is to be constructed over Whitney Creek, and traverse southward initially through a narrow valley corridor with steep valley side slopes. The road would then swing eastward, generally climbing in elevation to the well site. Total length of the access road would be some 2 km.

The geological zones of interest, the Livingstone and Mount Head Formations (Rundle Group) are typically thick, widespread, carbonate beds containing thin dolomitic reservoir lenses. These beds have experienced geological faulting and folding resulting in gas-bearing structural traps which trend northwest-southeast and form the major reservoir of the Waterton sour gas field.

1.3 Castle River Sub-Regional Integrated Resource Plan

In 1977 the Alberta Government (Government) issued a document entitled "A Policy for Resource Management of the Eastern Slopes" (Eastern Slopes Policy) to provide direction for integrated resource land use planning for the Alberta Eastern Slopes region. The policy was revised in 1984 to reflect the relationship among broad provincial goals and policy statements for resource management of the Eastern Slopes. It provides a reference point for regional plans which would define what, where, and how resources in an area would be managed to meet part of the provincial goals. Consistent with this policy, the Government approved the "Castle River Sub-Regional Integrated Resource Plan" (IRP) in 1985. This approval process included submissions from such groups as the Alberta Wilderness Association (AWA) and others as well as consultation with various Government agencies. The IRP stresses the protection of watershed, wildlife habitat, and recreation resources while allowing for the development of a wide range of other resources.

The sub-alpine upper Whitney Creek watershed where the proposed well would be located is within the Castle River Sub-Regional IRP. The IRP specifies eight land use categories, shown in Table 1, each having a main policy objective. As well, compatible land uses for each land zone are outlined in Table 2. The access road and well site described in the application are situated in designated Zone 5 lands of the IRP. The Zone 5 classification, Multiple Use, provides for the management and development of a full range of available resources (eg. timber, petroleum, and grazing) while meeting long-term objectives for watershed management and environmental protection. Where petroleum or timber development is permitted, it would be subject to special conditions and controls to ensure that the recreation intent is preserved and wildland character protected.

1.4 Preliminary Meetings

Prior to the hearing of the application, the Board had been made aware that a number of individuals and various public interest groups had concerns respecting the proposed well. In order to facilitate a more efficient hearing process, the Board arranged a pre-hearing meeting with the applicant and potential interveners in Pincher Creek on 18 May 1988. At the pre-hearing meeting interveners identified a range of environmental concerns, a majority of which were common to a set of concerns identified by the AWA. The Board also indicated that, to ensure an effective and efficient hearing process, those concerns be addressed in a common set co-ordinated by the AWA. The Board undertook to provide limited financial assistance to meet those objectives.

1.5 Hearing

A public hearing of the application commenced on 15 June 1988 in Pincher Creek before N. A. Strom, P.Eng., F. J. Mink, P.Eng., and E. G. Fox, P.Eng.

At the outset of the hearing a number of interveners requested that the Board adjourn to a later date in order to permit all parties adequate time to prepare for the hearing. The Board granted a deferral and rescheduled the hearing to commence on 16 August 1988. On 16 June 1988 the Board, its staff, Shell, and certain interveners walked the proposed access road and well site to gain a general impression of the land forms and general environmental setting.

Prior to the re-opening of the hearing, Mr. Mike Judd (Mr. Judd) of Diamond Hitch Outfitters (Diamond Hitch), a local outfitter and guide, advised the Board that he would not be able to attend the 16 August hearing because of work commitments. Accordingly, the Board convened a special hearing sitting in order to hear Mr. Judd's direct personal evidence. This sitting took place on 12 August 1988 at the offices of the Board in Calgary, and was attended by Mr. Judd, Shell, and their respective representatives.

The public hearing of the application continued in Pincher Creek on 16, 17, 18, and 19 August 1988. Those who appeared at the hearing are listed below.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Shell Canada Limited (Shell) R. B. Low	J. R. Tilbe, P.Eng. R. T. Staysko, P.Eng. J. D. Scott Dr. D. A. Mead R. Webb, R. Webb Environmental Services Ltd. D. Hemphill, P.Geol. J. L. Kansas, Beak Associates Consulting Ltd. M. Raine, Beak Associates Consulting Ltd.
Pincher Creek Chamber of Commerce K. Dickie	K. Dickie
Aris Instrument Services Limited S. Aris	S. Aris
Alberta Wilderness Association (AWA) V. Pharis B. Horejsi D. Pachal	Dr. T. Power, University of Montana Dr. C. Jonkel, University of Montana G. Hornbeck D. Coulombe, P.Eng., Calco Geological and Engineering Consultants D. Mayhood, FWR Freshwater Research Limited

THOSE WHO APPEARED AT THE HEARING (continued)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
	D. Pachal V. Pharis Dr. B. Horejsi
Diamond Hitch Outfitters (Diamond Hitch) J. Scarth	M. Judd Dr. T. Power, University of Montana D. Coulombe, P.Eng., Calco Geological and Engineering Consultants G. Hornbeck
Federation of Alberta Naturalists H. R. Gardner	H. R. Gardner
Lethbridge Fish & Game Association R. Stewart	R. Stewart
Public Advisory Committees to the Environment Council of Alberta (Public Advisory Committees) M. Posey	M. Posey
National Audubon Society H. Marble	H. Marble
R. E. Wolf	R. E. Wolf
J. Huntley	J. Huntley
J. Tweedie	J. Tweedie
K. Dickie	K. Dickie
D. H. Sheppard, Ph.D.	D. H. Sheppard, Ph.D.
Energy Resources Conservation Board staff A. Broughton R. Creasey D. Hill N. Lord, C.E.T. E. Shima, P.Geol. *W. Wishart, Cert.Bio.	

* For this application, the Board retained the services of Mr. W. Wishart, a certified wildlife biologist, to assist the Board staff in assessing environmental evidence.

Although submissions opposing the application were filed by the Glacier Two Medicine Alliance, the Pincher Creek Area Environmental Association, the Southern Alberta Environmental Group, the State of Montana Wilderness Society, and the Willow Valley Trophy Club, no persons came forward at the hearing to speak to those submissions. The Town of Pincher Creek filed a written submission supporting the application but did not present a witness at the hearing.

1.6 Position of Respective Parties

(a) Views of Shell

Shell submitted that it wished to continue the timely and orderly development and production of the Waterton Field. Noting that it had already received a mineral surface lease (MSL) granting surface rights for the proposed access road and well site, Shell contended that the matter before the Board should be confined to consideration of the application for a well licence and not broader issues raised by some interveners. In its opinion, the drilling of the proposed well was consistent with the multiple land use policies established by the Eastern Slopes Policy and the IRP for the Whitney Creek area. It was therefore Shell's desire to proceed with the well and Shell submitted that the earlier the Waterton Field was depleted, the earlier field restoration could begin.

(b) Those in Support of the Application

Those parties who filed submissions in support of the application encouraged the drilling of the well and the activities of Shell as a positive factor in the economy of the Pincher Creek area. They submitted that many of the area's residents and local businesses derived the greater part of their economic livelihood from either direct employment by Shell or from supplying service or supportive functions to the petroleum industry. This activity was therefore extremely important to maintain the standard of living they currently enjoyed and, moreover, would sustain a firm economic base in the Pincher Creek area. It would also provide an extended period in which other non-petroleum related activities could be developed for the time when the hydrocarbon reserves were depleted.

The Town of Pincher Creek submitted a letter stating that a resolution had been passed by the Town Council supporting the application.

(c) Those Parties Opposing the Application

Those parties opposing the application consisted of both public interest groups from Canada and the United States of America, local interest groups, local area residents, and concerned citizens residing in Alberta. While opposing the specific application before the Board, these parties

raised concerns over the developments in and impacts on the Whitney Creek drainage and general area as a whole. Their submissions generally reflected environmental impact concerns including recreational, ecology conservation, and local commercial guiding perspectives. They also submitted that there might be greater net economic value in leaving the area of application undisturbed and in a natural state as compared with any net economic gain which could be realized through the development of the natural gas resources. They questioned the need for the specific well in this relatively undisturbed wildland area and suggested that the potential cumulative environmental impacts of this and future well developments should be weighed in determining the prudence of approving or denying this development. They submitted that there was a lack of environmental information available to assess what impacts would occur and submitted that as a minimum, future drilling activities in the upper Whitney Creek drainage area should be deferred until sufficient environmental assessments had been conducted.

2 ISSUES

The Board believes the issues are

- the Board's jurisdiction in considering the application,
- technical matters pertaining to the application,
- gas resources values,
- wildland/recreation values,
- ecology concerns: biosphere, wildlife, fisheries, vegetation/ reclamation, and
- the need for an ongoing consultative process.

3 THE BOARD'S JURISDICTION ON THIS APPLICATION

3.1 Views of Shell

Shell submitted that the Government, in approving the IRP, designated the area in which this applied-for well is to be located as "Zone 5: Multiple Use", and that oil and gas activities are a "compatible use" under the Table of Compatible Activities By Land Use Zone set out in the IRP. Shell also submitted that the purpose of the public hearing of the application was in essence to continue the consultative process which has been characterized as "integrated resource management", and that the concept of integration suggests the reconciliation of diverse interests, not the exclusion of one use to the benefit of another use. Shell pointed out that, while the Board's mandate as found in section 2(d) of the Energy Resources Conservation Act pertains to controlling pollution and ensuring environment conservation in the exploration for, processing,

development, and transportation of energy resources and energy, it does not contemplate exclusion of energy resource development. Shell cautioned that it was not the purpose of the Board hearing of this application to review the Eastern Slopes Policy or the IRP for this area as there are other mechanisms established by the Government for those purposes. Rather, the purpose was to continue the consultative process to achieve integrated resource management. It submitted that the mandate of and the challenge for the Board within the integrative process is to provide for the development of the energy resources and, at the same time, to ensure environment conservation and pollution control.

3.2 Views of the Interveners

Diamond Hitch submitted that the relevant statutory provisions are section 2(d) of the Energy Resources Conservation Act and section 4(c) of the Oil and Gas Conservation Act, which state that the purposes of those Acts are:

> "2(d) to control pollution and ensure environment conservation in the exploration for, processing, development and transportation of energy resources and energy;" and

> "4(c) to provide for the economic, orderly and efficient development in the public interest of the oil and gas resources of Alberta;"

as well as section 14(1) of the Oil and Gas Conservation Act, which states:

> "14(1) On receiving an application for a [well] licence, the Board may grant the licence subject to any conditions, restrictions and stipulations that may be set out in or attached to the licence or it may refuse the licence."

In Diamond Hitch's view, the two key provisions are that the Board "may", not "shall", grant the licence and that the Board's specific mandate is to provide for energy development in the public interest. It further submitted that past Board decisions, notably the Jutland* and

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* ERCB Decision D 86-2, "A Report on an Application by Shell Canada Limited to Drill a Critical Sour Well in the Jutland (Castle River South) Area, June 1986", 3 June 1986.

Prairie Bluff** decisions, which apparently relegated environmental considerations to matters of mitigation, reflected the wrong approach, given the Board's statutory mandate. Rather, Diamond Hitch submitted that the Board's statutory mandate should be interpreted so as to ensure that the values associated with all of the resources involved, including environmental considerations, are properly considered in the course of weighing the costs and benefits associated with the proposed energy development. It submitted that the Board's statutory mandate is sufficiently broad to allow the Board to achieve this integration of economic and environmental concerns in its decision on an application for a particular development, and that this integration requires consideration of environmental concerns as an integral part of the decision whether or not to approve the applied-for development. It noted Board Decision D 77-18***, wherein the Board recognized that it may deny a well licence application where the economic impact on the surface exceeded the economic benefits from the subsurface resource or where the impact on the natural environment was unacceptable.

Diamond Hitch noted that the Board's well licence application process represents part of a larger approvals process, including the acquisition of the Alberta Crown Petroleum and Natural Gas Lease, which is issued without regard for environmental considerations, and the issuance of an Alberta Crown MSL. It argued that the deference of the latter process to the Board's jurisdiction over environmental concerns is evident in the Department of Forestry, Lands and Wildlife's (FLW) insistence on a Board well licence being issued prior to Shell's commencing any clearing or construction under the MSL. Moreover, it noted that the Department could not have had regard for the Environmental Overview prepared for Shell on this ERCB application, because the MSL had been issued prior to the preparation of that Overview. Further, given that the Minister of the Environment has indicated that no Environmental Impact Assessment pursuant to section 8(1) of the Land Surface Conservation and Reclamation Act will be required in respect of this applied-for well, it argued that the Board is the only independent tribunal with the statutory mandate to consider publicly the overall costs and benefits associated with this proposed development.

Diamond Hitch further submitted that the IRP assigns priority to the recreational value and the maintenance of the wildland character of the area, as evident from the Resource Management Objectives, and that the

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** ERCB Decision D 87-16, "Shell Canada Limited Well Licence Application Waterton/Prairie Bluff Area", 26 October 1987.

*** ERCB Decision 77-18, "Decision on the Application by Consolidated Oil and Gas (Canada) Ltd. for a Licence to Drill a Well in the Ghost Pine Area", 17 October 1977.

IRP, in specifically mentioning the Whitney Creek Valley as a "Multiple Use Zone 5", states that localized areas with recreation value must be protected as directed by the guidelines in the IRP. It argued that the IRP clearly gives priority to the environmental resources of the area and that if such resources cannot be protected while ongoing natural gas exploration and development takes place, it is the natural gas activity that is to be restricted.

In conclusion, Diamond Hitch posed two questions relating to the Board's jurisdiction pursuant to the above statutory provisions:

1. Does the Board consider itself to have the jurisdiction to deny this applied-for well licence where the impact on the natural environment is unacceptable or where the overall economic impact of the surface and environmental effects are found to be greater than the economic benefit that could be derived from the subsurface resources?

2. If the answer to the second part of Question 1 is yes, is it adequate for the Board to have regard to the royalty payments that could potentially accrue to the Government of Alberta, or must there be some consideration of the environmental cost that could potentially result from the granting of this applied-for well licence?

Diamond Hitch urged the Board to deny this application, either because the impact on the environment is unacceptable, or because Shell has not established whether or not the impact on the surface is greater than the economic benefit from the subsurface resource.

The AWA and other interveners supported Diamond Hitch's submissions. In particular, the AWA argued that the Board has the jurisdiction to consider the environmental and public concerns raised by the interveners, and that FLW must have seen merit to public hearing input and the concerns raised by those opposing the applied-for well, because it prohibited surface activity under the MSL until the Board has granted the well licence. The AWA urged the Board to exercise its jurisdiction over environmental matters and to deny the application.

3.3 Views of the Board

The Board recognizes that its jurisdiction on this application includes both section 2(d) of the Energy Resources Conservation Act, with respect to controlling pollution and ensuring environment conservation in energy resource and energy matters, and section 4(c) of the Oil and Gas Conservation Act, with respect to providing for the economic, orderly, and efficient development in the public interest of the oil and gas resources of Alberta. The Board further agrees with Diamond Hitch that its jurisdiction on this application pursuant to section 14(1) of the Oil and Gas Conservation Act gives it a discretion to grant the application, with or without such conditions, restrictions, and

stipulations as it may prescribe, or to deny the application. The Board also agrees with Shell that it is not within the Board's mandate to review elements of the Eastern Slopes Policy or the land use management guidelines set out in the Castle River IRP, including the particular ones applicable for the upper Whitney Creek basin.

With respect to Diamond Hitch's first question, the Board agrees that all relevant factors, specifically including environmental concerns and other potential surface impacts of the applied-for well licence, are to be considered in reaching a decision on this well licence application. As stated in the Board's Decision Report 77-18****:

> "In the Board's view there are several situations where it might either deny a well licence application or grant it subject to relocation at the surface or to certain safety-oriented conditions. These situations are discussed separately in the order listed below:
>
> (a) Where there is a serious hazard to people.
>
> (b) Where the impact on the natural environment is unacceptable.
>
> (c) Where an equally acceptable alternative is available which would significantly reduce the impact on the surface.
>
> (d) Where the economic impact on the surface would be greater than the economic benefits that could be derived from the subsurface resource."

The Board notes Shell's view that where Multiple Land Use is designated, the challenge is to provide for environmental protection and pollution control, while allowing integrated development to proceed. In Diamond Hitch's view this would lead the Board to consider applications only from the view of mitigating impacts.

Diamond Hitch argued that the Board must consider the merits of the application by evaluating the broad environmental impacts of the well and that the comparative surface and subsurface resource values including economic costs/benefits, should be the primary considerations.

**** Decision on the Application by Consolidated Oil and Gas (Canada) Ltd. for a Licence to Drill a Well in the Ghost Pine Area. Decision 77-18, Application No. 770395.

The Board's general view is that where Zone 5 Multiple Use is the land use classification and there are opposing consequences for surface and subsurface land use, the only way to reasonably accommodate those uses while achieving minimum combined negative impact is through appropriate mitigative actions. These actions may include technical amendments such as clustering of several surface well sites at a single site combined with directional drilling to subsurface targets and using one common transportation corridor, or environmental amendments such as the development of compensatory environmental enhancement programs in a local eco-region, providing for aesthetic improvements and the application of stringent environmental protection measures in the immediate zone of impact. These are an outcome, not a first consideration, and in that respect the Board would not regard the past decisions of the Board, including those cited by Diamond Hitch, as examples of environmental considerations having been relegated to matters of mitigation.

The Board believes that where the evidence presented on an application leads it to conclude that the impact of an applied-for well licence on the environment would be unacceptable, then the Board has the jurisdiction to deny the application, without prejudice to the applicant to re-apply, citing measures to be taken which would render the proposed well acceptable.

Similarly, where evidence was led which satisfied the Board that the overall economic impact of the surface and environmental effects was very significant, whereas the economic benefit to be derived from the subsurface resource was not significant, then the Board believes that it has jurisdiction to deny the well licence application.

Subject to the foregoing comments, the Board answers Diamond Hitch's first question, "Does the Board have the jurisdiction to deny this applied-for well licence?", in the affirmative.

Diamond Hitch's second question, "Must the Board consider environmental cost as well as potential royalty benefit?", pertains in the Board's interpretation to its mandate "to provide for the economic, orderly and efficient development in the public interest of the oil and gas resources in Alberta", pursuant to section 4(c) of the Oil and Gas Conservation Act. The Board sees "the public interest" as a very broad concept. One component of "the public interest of Alberta" is the revenues expected to accrue to the people of Alberta, by way of royalties or taxes, if the well is successful.

In aggregate, however, the Board believes that "the public interest" includes many factors other than the monetary values attributed to a resource. Some of these are capable of economic quantification and some are not. Specifically, environmental costs or impacts can be interpreted in both biophysical and aesthetic form. Such impacts go on

continuously, much, if not most, through man-induced processes and some through natural processes. While environmental impacts usually are measured in shades of concern from imperceptible to massive, an imperceptible impact regionally could be a massive impact in a micro-region. A bottom line of what would be considered an unacceptable cost or impact on the environment would be where an irreversible loss or alteration of an aesthetic treasure or destruction of an endangered faunal or floral species was indicated. Hence the Board answers Diamond Hitch's second question in the affirmative, but with the qualification that the Board regards economic considerations to be only one of numerous relevant factors to be assessed in determining whether or not a well represents "economic, orderly and efficient development in the public interest of the oil and gas resources of Alberta".

3.4 MSL in Relation to IRP

The Board has carefully considered the hearing participants' submissions with respect to the IRP and the MSL issued by the Government.

With respect to the IRP, the Board notes that the subject surface lands are classified "Zone 5: Multiple Use" under the IRP which lists "petroleum and natural gas exploration and development" as a "compatible use", together with the sixteen other "compatible uses". The Board also notes that the Table of Compatible Uses by Land Use Zone set out in the IRP states that "for these and any other activities, the possibility of whether they should or should not take place in a particular area must always be measured against the fundamental management intentions for that zone". Section 5.4 of the IRP states at page 68, for this Area D, "the primary intent is to provide for a wide range of extensive recreation opportunities", and at page 70 that "Whitney Creek ... (has) been designated as Multiple Use (Zone 5); however, even within the Multiple Use Zone localized areas with recreation value must be protected as directed by the guidelines in this plan". The IRP lists "watershed" and "recreation" as the first and second resource management priorities in Management Area D, with "Minerals" listed thereafter in alphabetical order. The Resource Management Guidelines for Minerals state (IRP, page 77) that "Petroleum and natural gas step-out wells may be permitted if it can be demonstrated that the high recreation values of the resource management area can be maintained".

The Board agrees with Shell that it is not within the Board's mandate to undertake a review of the IRP land use management guidelines in connection with consideration of this well licence application. Conceivably the Government might initiate such a review if the Board were to find environmental impacts to be unacceptable, but still such a review would not be part of the Board's mandate. It follows that the land use guidelines set in the IRP must be regarded as precepts for environmental protection measures to be considered in connection with a well licence application. Nevertheless, the Board does not believe that

the IRP predetermines its disposition of the application. The Board recognizes that the IRP represents a very useful land use planning initiative by the Government which continues to include opportunities for industry and public input. Accordingly, the Board would give considerable weight to the IRP in considering the evidence filed by the parties and in reaching a decision on an application.

As has been noted by Shell, the MSL lies fully within IRP Zone 5 Multiple Use lands. The Board also notes that some of the MSL lands in question are in close proximity to IRP Zone 1 prime protection lands. The MSL is subject to a number of environmental conditions, including the condition that no activity be conducted within the bed of Whitney Creek between 1 September and 15 August without the written approval of the Alberta Forest Service and the Fish and Wildlife Division. Accordingly, the Board notes that environmental protection was a consideration in issuing the MSL. Pursuant to section 14.1(3) of the Oil and Gas Conservation Act, the Board does not have the authority to prescribe the location of the applied-for access road or conditions relating to its construction, unless it obtains the prior approval of the Minister of Forestry, Lands and Wildlife, which approval may be given with or without conditions. Accordingly, if the evidence filed at the hearing indicated that there was a need to address matters pertaining to the access route, the Board would have to obtain such authority from the Minister.

4 TECHNICAL MATTERS PERTAINING TO THE APPLICATION

4.1 Need for the Well and Appropriate Subsurface Location

(a) Views of Shell

Shell proposed the 6-30 well to access reservoirs in Sheets IVc and possibly IIIb of the Waterton thrust-fault complex, and to provide further information on the southern extent of these reservoirs. The primary target is interpreted as the highest area on an anticlinal structure trending northwesterly from section 20, township 4, range 1, west of the 5th meridian.

Shell reported that the fault repeats of target Mississippian age Mount Head and Livingstone Formations are thick carbonate units containing thin, low porosity and permeability dolomitic reservoir beds, with little natural fracture enhancement. Lateral reservoir drainage continuity in the beds may be limited by small fault displacements. The Rundle beds dip 15° to 20° in a direction 50° west of south, and strike 40° west of north.

Shell provided a range of raw recoverable gas reserves for section 30. The lower value, 1050 million cubic metres per section, was based on the nearest offsetting well, WATERTON 13. The higher, 1350 million cubic

metres per section, was an average from three tested wells in the same sheets. Shell estimated the initial gas deliverability to be 150 thousand cubic metres per day.

Shell stated that it required the 6-30 well in order to meet estimated future deliverability requirements of the Waterton Gas Plant. It stated that the reserves in section 30 would not be recovered if a well is not drilled in the vicinity.

Shell stated that in order to efficiently drain the reservoir, which is expected to have comparatively low permeability, development on a spacing similar to that of the main Sheet IV Rundle "D" Pool would be appropriate, that being about a 900-metre interwell distance. It considered that wells draining Sheets IIIb and IVc to the north would effect very little, if any, drainage in section 30 since the nearest well, WATERTON 13, is greater than 1500 metres away. Existing wells to the south and east were, by Shell's interpretation, located in the non-communicating separate major thrust Sheets III and IV. Therefore a well drilled in or near section 30 would be required to access the prospective gas reserves.

In supporting the need for the well, Shell indicated that the Waterton Field's capacity to produce is declining at a rate of 10 per cent per year or slightly higher; and that in the previous year, the existing wells were producing at 70 per cent of maximum capacity.

If the 6-30 well successfully confirms the predicted structural trend, Shell indicated that possibly three more wells, one north and two south of the 6-30 well, may be required to access the reservoir.

(b) Views of the Interveners

The AWA and Diamond Hitch believed that the well would not be needed before the early 1990s to maintain the desired level of deliverability to the plant. Assuming a 5 per cent Waterton Field production decline, AWA estimated Shell would require an additional three wells per year in order to maintain plant production near current levels. AWA suggested that the combination of nine wells drilled and/or proposed by Shell, including the 6-30 well, over a 2-year period would represent excess and unneeded capacity.

To avoid impacts on the upper Whitney Creek area and yet partly meet Shell's objectives, the AWA and Diamond Hitch proposed two possible alternatives to drilling the 6-30 well. First, they indicated that 30 per cent of reserves under section 30 could be drained by either existing or possible future wells located in other sections. They suggested that existing wells in 2-29-4-1 W5, 12-29-4-1 W5, 7-31-4-1 W5, and 16-26-4-2 W5, and future possible wells in section 20-4-1 W5, 12-31-4-1 W5, and 7-35-4-2 W5, could partially drain the reserves. They

were not prepared, however, to quantify the drainage by each well. A second alternative by which well drilling could be delayed would utilize a gas storage scheme whereby Shell would continue to produce gas at capacity levels during the lower demand summer months and other off-peak demand periods, store it in a suitable reservoir, and reproduce it during the winter or peak demand periods. This alternative was based on the understanding that Shell had not been producing its wells at capacity during the summer because of seasonal market fluctuations.

(c) Views of the Board

Upon review of the evidence available, the Board accepts that from an exploration viewpoint the proposed subsurface location in 6-30-4-1 W5, as shown in Figure III, is potentially an optimum subsurface location for defining extension of Sheets IVc and IIIb reservoirs.

Considering the production performance of other wells in this structure and the general character of the reservoir, the Board concludes that raw recoverable gas reserves will be in the order of 1000 million cubic metres for each well successfully targeted in the structure. It is therefore the Board's understanding that up to approximately 4000 million cubic metres of raw gas may be shown to be recoverable assuming a well bottomed at 6-30 proved successful and three additional wells were successfully drilled to access the reserves.

In the Board's view, the suggestion by the AWA and Diamond Hitch that reserves to be accessed by the 6-30 well could instead be drained through the existing well, 16-26-4-2 W5, and possible wells in section 20-4-1 W5 and 7-35-4-2 W5, fails to take into account the comparatively low permeability of the Sheets IVc and IIIb reservoirs. Also, the other four wells suggested by the AWA, wells 2-29-4-1 W5, 12-29-4-1 W5, 7-31-4-1 W5, and a possible future well, 12-31-4-1 W5, would not encounter the reservoir structures of interest. In summary, the Board concludes that much of the potential recoverable gas in the structures within the lands of interest would not be drained without the 6-30 and other prospective wells referred to by Shell.

Respecting the matter of the need for the 6-30 well at this time, the Board has reviewed the publicly available production decline information from existing wells in the Waterton Field, and confirms that, as pointed out by Shell, the current decline rate is approximately 10 per cent per year or roughly 1 million cubic metres per day per year. From this it could be inferred that there is a need for the well to help maintain deliverability near current levels and to expedite depletion of the Waterton reservoir complex.

4.2 Proposed and Alternative Surface Locations

(a) Views of Shell

Several potential surface locations to access the proposed bottom-hole target in section 30 were examined by Shell as follows:

- Prairie Bluff locations 13-29-4-1, 9-30-4-1, and 8-30-4-1 (site of existing Prairie Bluff 12-29-4-1 which was drilled in 1988)
- Shell's optimum surface location 8-25-4-2 W5
- Shell's alternative surface location 1-25-4-2
- Shell's chosen location 2-25-4-2

In selecting potential sites, Shell considered the direction and degree of natural drilling deviation, the topographical constraints involved in road and lease construction, and side slope stability for both the access road and the well site. Also, it considered the relative environmental impacts of one location over another, and indicated that generally the lower the well site elevation, the lower the environmental impact.

Shell indicated that

- the Prairie Bluff locations were rejected because of the extremely large lateral displacement and the extreme difficulty of drilling against the natural deviation tendency;
- the optimum location at 8-25-4-2 was rejected because of topographical constraints including steep and unstable side slopes;
- the alternative location at 1-25-4-2 was also rejected because of unacceptably steep road grades.

Shell argued that the applied-for location at 2-25-4-2 represents a balanced consideration of drilling on the natural northeast trending deviation to access the 6-30 subsurface target and the objective of continued integrity of the road and well site side slopes in mountainous terrain.

(b) Views of the Interveners

The position of AWA and Diamond Hitch generally was that the upper Whitney Creek basin should not be used for oil and gas well sites and that only environmentally acceptable locations should be employed for accessing the geological structure of interest. In that regard, the AWA and Diamond Hitch suggested that drilling along strike from Lsd 9 or 16 of section 19-4-1 might be feasible using slant-hole drilling techniques to reach a target in 6-30. Though they acknowledged that the slant rig required to drill from this location has not yet been built, they believed that the technology would eventually be developed to overcome

more and more difficult drilling access problems while avoiding disturbance of mountain terrain. They suggested that Shell with its outstanding technological capability should take the lead in developing such a slant-hole rig.

(c) Views of the Board

The Board believes that a surface location for a well site in this particular area must have regard for road and well site construction feasibility in mountain terrain, for drilling and production safety and for environmental protection. The Board notes that Shell has considered several locations in the process of identifying the applied-for location. Mountain terrain with resulting land instabilities would eliminate a very large number of possible locations that might otherwise be considered. As well, consideration must be given to the natural physical tendency for the drill hole to "drift" in a direction normal to the steeply dipping beds in the foothills. Attempting to drill against this natural drilling deviation can lead to complications, including potential unsafe conditions which must be given thorough technical consideration. In that regard, the Board agrees with Shell that attempting to access the 6-30 target by drilling from an existing site on Prairie Bluff would involve very large horizontal displacements against the natural drift, would be complex, and would possibly introduce risks not prudent for sour gas drilling and production. Drilling from the surface location in section 19-4-1 W5 proposed by the AWA and Diamond Hitch would, in the Board's opinion, involve similar complications and future production operation risks.

As to slant-hole drilling, the Board is not satisfied that sufficient evidence was presented to support the position that it is technically feasible to build such a slant-hole rig or use such technology in this mountain region.

On the combined considerations of site construction feasibility and stability, and drilling and production safety, the Board is satisfied that the only reasonably safe location would be somewhere in the lower slopes of the Whitney Creek drainage basin. Therefore, subject to consideration of environmental and aesthetic factors relating to the Whitney Creek basin, the Board is inclined to agree with Shell that the applied-for 2-25-4-2 surface location is near optimum.

5 GAS RESOURCE VALUES

5.1 Views of Shell

Shell did not provide an economic study of the benefits associated with the proposed development. However, as a nominal estimate it submitted that some 30 million dollars in royalty payments would accrue to the province over the 20-year life of the well. In addition, substantial revenue would be generated from the sale of sulphur and natural gas liquids produced in conjunction with the gas. Shell estimated that

over the life of a well some 75 million dollars would be generated in taxes and royalties of one kind or another from the development of a section of gas reserves. It did not estimate the benefits that may accrue to others in the local economy or attempt to identify costs associated with the development.

5.2 Views of the Interveners

A submission from the Pincher Creek Chamber of Commerce, presented by Mr. Dickie, stated that the welfare of the local community was dependent on the gas industry and that the majority of local residents favoured continued development as proposed by Shell. Mr. Dickie claimed that deferring drilling as suggested by AWA and others would unnecessarily retard long-term adjustments that would eventually be needed to convert to an economy based on renewable resources like tourism in place of non-renewable sour gas reserves. Mrs. Aris also spoke in support of the application, stating that Shell's activities contribute to a vibrant community with a healthy, competitive business environment.

Diamond Hitch and the AWA, represented by Dr. Power, questioned the economic benefit from the well as interpreted by Shell. Dr. Power emphasized that when there are readily available substitute sources for the gas, the net economic cost associated with not producing the gas from the Whitney Creek well should not be considered its full market value but only the cost advantage that the gas from the Whitney Creek well would have over other gas sources. In this instance Diamond Hitch suggested that there are many readily available substitute sources for the incremental gas production proposed for Whitney Creek. On that basis, Dr. Power presented a hypothetical example and argued that the real economic cost associated with not drilling may be as low as 5 per cent of the value of the gas. He also noted that where resource extraction economics experience decline, the net value of resource development may be negative.

5.3 Views of the Board

The Board notes that the Pincher Creek economy has functioned for many years on a combination of agriculture, resource extraction, and tourism. It believes that land use policies, including those set out in the Castle River Sub-Regional IRP, are aimed at gradual transition to more reliance on tourism as non-renewable resources are depleted. In large measure, the Board accepts the applicant's calculation that many millions of dollars in royalties and taxes may result from gas produced from the applied-for well. Because the proposed well development will sustain local economic activity with no need to spend public funds for added infrastructure, the local economic benefits appear to be clearly positive. This conclusion is in accord with the arguments posed by Aris and others.

The Board notes the general framework for preparing the cost/benefit analysis supplied by the AWA and Diamond Hitch. While the concept has some merit, the Board cannot accept that it needs to be applied in the

current instance where broad policies of land use categories that permit multi-purpose use have been established. To some degree the Board believes these concepts have been applied in the integrated resource evaluation process. The Board dismisses any inference that the hypothetical example and assumption used to illustrate the methodology would reflect a balanced view of the actual net value of the potential gas resource in this application. Consideration is given to wildland/recreation values in the following section.

6 WILDLAND/RECREATION VALUES

6.1 Views of Shell

Shell acknowledged that the Whitney Creek basin is a de facto wilderness, in that it is essentially undeveloped in any major way and, except for some older truck trails, retains its natural attributes. The applicant also acknowledged that those existing wildland characteristics will decline sharply during the drilling and production phases of the proposed well, but maintained that the existing aesthetic quality can be recreated upon abandonment of the wells.

Shell indicated that its plan for the 6-30 well included measures to reduce aesthetic impacts, including the following:

- avoiding sensitive terrain
- minimal tree clearing
- temporary reclamation
- stabilizing soils and revegetating road and well-site slopes
- using earth-tone colours on well facilities
- using dull-appearance wire and wood power poles

Shell also indicated that access to the area would be restricted by means of a gate which would be placed on the bridge nearest to the WATERTON 13 well. The gate would be manned during the construction phase and would be locked during the production phase. Access to the new road via the existing truck trail would be blocked by boulders and other obstructions erected on the north bank of the creek.

Shell acknowledged that scenic quality ratings will likely be impaired from most viewing points in the upper slopes of the Whitney Creek basin throughout the operational life of the well. However, reclamation will ultimately return the area to its natural growth process, with the well site and access road ultimately becoming unnoticeable because of tree growth.

6.2 Views of the Interveners

Diamond Hitch and AWA presented Dr. Power as a witness concerning long-range economic costs versus benefits. Dr. Power cited studies from the United States which document the importance of undisturbed natural landscapes to attract population relocation. Dr. Power proposed that

the environmental resources of Whitney Creek may have a direct and substantial value that could be compared to the value of the gas if an appropriate economic evaluation were done. He contended that proper economic analysis must take into account the economic benefits resulting from strong preferences by people to live near large wildland areas.

Dr. Power argued that tourism based upon the wildland characteristics of a region can provide a stable and growing local economic base. Any development, including gas development, that threatens those resources jeopardizes the long-term economic stability of the region once the gas production systems have been abandoned. As well, Dr. Power stressed the potential cumulative impact of gas development on wildland areas, and suggested that incremental economic analysis based upon the impacts of a single well would be inappropriate.

The AWA asserted that wilderness and wilderness qualities cannot be recreated by reclamation efforts, and also pointed out that the IRP frequently states that wildland areas in the region should be protected. The AWA also claimed that the wildland of Whitney Creek helps to accommodate some of the recreational pressure being put on Waterton National Park.

Diamond Hitch presented evidence regarding the potential impacts of the proposed well and access road on its hunting and trail riding operations. Mr. Judd stated that the wildland characteristics of the upper Whitney Creek basin are a necessary component of his clients' expectations. The business is dependent on providing the opportunity for a wilderness experience within an unmodified natural environment. Diamond Hitch presented evidence from former clients, which stated their views on the impacts of this development proposal. It was stated that the gas well and road development in the Whitney Creek basin would result in an overall deterioration of those natural resources which helped support the outfitting business. Further, those impacts would be significant and long term.

Mr. Judd stressed that the importance of this drainage to his business went beyond the time physically spent in the Whitney Creek area. The wilderness experience necessary for Diamond Hitch to conduct its operation includes wildlife, fish, vegetation, scenery, and an opportunity for solitude. Offering clients the chance to experience recreation in an undeveloped natural wilderness environment is critical. In the view of Diamond Hitch, the proposed well and access road will have signficant long-term effects on its business which cannot be offset, particularly in light of the numerous existing sour gas developments in the adjacent valleys.

Diamond Hitch did not believe that wilderness or wildland environments can be successfully reclaimed or recreated once they have been altered. Thus, Diamond Hitch would suffer a permanent serious impairment of the factors on which it bases its business.

Mr. Hornbeck, appearing on behalf of Diamond Hitch and AWA, indicated that the elk hunting season annually accounts for more than 22 million dollars in business in the province. These significant benefits derived from the existing provincial elk population of some 15 000 are said to be at risk because compensating programs have not been instituted to offset cumulative reductions to elk habitat due to expanding industrial incursions.

Mr. Tweedie contended that the value of Whitney Creek to remaining wilderness inventory is vastly greater than the near-term commercial value of the gas reserves.

Mrs. Huntley noted the spiritual value of Whitney Creek, and submitted that leaving it in a state of living wilderness is of significantly greater value to the people of Alberta and the nation than the monetary value of producing the gas resources.

6.3 Views of the Board

The Board believes an important consideration is that the Castle River IRP provides that "Petroleum and natural gas step-out wells may be permitted if it can be demonstrated that the high recreation values of the resource management area can be maintained".

In that regard the Board would agree with Diamond Hitch and the AWA that the environmental resources of upper Whitney Creek have an economic value which may well increase substantially as time, perhaps measured in decades, goes on. Such values tend to be largely judgmental but should be factored into the final consideration of the public interest. Also, though its mandate is to facilitate economic, orderly, and efficient development of Alberta energy resources, the Board nonetheless recognizes that there will be particular wildland areas where preservation of the natural setting, such as parks, would be clearly of greater economic merit than allowing an energy development to proceed. Mr. Hornbeck indicated the annual economic return resulting from hunting for elk throughout the province but he could not quantify the local benefit, presumably for lack of data. Otherwise the hypothetical examples put forward by the AWA and Diamond Hitch are simply not substantive evidence of long-range economic benefits accruing through wildland/recreation resources in upper Whitney Creek. On the contrary, it is clear from the terms of the IRP that the Government has not found it appropriate to restrict the use of this area as a park or wilderness as proposed by the AWA and others.

Nothwithstanding the above, the Board believes that any development in the area requires a great measure of sensitivity to environmental matters. If the proposed 6-30 development proceeds, some negative impact on the wildland/recreation values will be felt by those of the public using Whitney Creek, as well as the clients and business of Diamond Hitch. It is unlikely that tourism activity would be affected to any measurable degree in the area as a result of this activity.

The Board notes that Shell agreed that the wildland characteristics would decline sharply and remain in decline during the approximately 20-year life of the well. If that is the consequence, the Board is inclined to agree with Diamond Hitch that the 6-30 well plus other possible follow-up wells could derogate from Diamond Hitch's use of the area as a commercial guide marketing wilderness adventures, and this derogation would be both significant and very long term. As well, if the wildland values are perceived to decline sharply during the life of the well, there would be very limited possibility of achieving integrated land use compatibility for Diamond Hitch and Shell use of the area. The Board notes that Diamond Hitch does not have exclusive jurisdiction. To the extent that the value of this area is derogated for wildland value, it represents a loss to society at large until reclamation of the area is complete. The ultimate degree to which this would impact Diamond Hitch is largely a question of judgement and unlikely to be reconciliable.

With respect to the AWA and Diamond Hitch submissions that wilderness and wildland qualities cannot be reclaimed or recreated, the Board believes that the question of reclaimability or re-creation must be assessed in terms of two aspects. The first is the degree of wilderness alteration related to the particular development and the second is the degree of environmental restoration that can be achieved.

In this case, the Board is satisfied that the degree of environmental impact from the applied-for development is not significant. In particular, the Board notes that the proposed access road and well site would occupy about 7 hectares of the approximately 1500 hectares of the Whitney Creek basin and if the well proves successful, the access road would be used only about three times per week during the production of the well. Moreover, the Board accepts that the route of the proposed access road was chosen to minimize visual impacts.

The Board has also considered the degree of environmental restoration that can be achieved. On the issue of the reclaimability of this land and the feasibility of physical reclamation, neither the AWA nor Diamond Hitch provided specific evidence that reclamation was not possible. The Board believes that reclamation is feasible and will be achieved in time. In reaching this conclusion, the Board recognizes that for a period of time, which includes the producing life of the well and a period of reclamation thereafter, the presence of the access road and the well will impact on the wilderness character of the area. The Board is satisfied that over time measured in decades the wilderness character of this area could be restored.

In spite of the foregoing conclusions, in regard to the long-range IRP objective of maintaining the high wildland recreation value of the area, the Board believes, if the 6-30 well were to proceed, it would be critical that ongoing consultation among FLW, Shell, Parks, and others be continued so as to promote maximum practical protection of the upper Whitney Creek wildland area. Others, such as Diamond Hitch, the

Federation of Alberta Naturalists, the Public Advisory Committees of the Environment Council of Alberta, Lethbridge Fish and Game Association, AWA, and local tourism and recreation businesses should be provided an opportunity for input. The Board believes that having such a process in place would allow interested parties to bring proposals forward to protect the natural and scenic values of the area to the extent possible and to later facilitate rapid reclamation and restoration of abandoned roads and well sites.

The prospects for land reclamation are discussed in Section 7.4.

7 ECOLOGY CONCERNS

7.1 Biosphere Protection Concept

(a) Views of AWA

The AWA spoke of the UNESCO-initiated program of Man and the Biosphere, which declared Waterton Park and adjacent lands a biosphere reserve in 1979. They pointed out that the Canadian Government has invited the Alberta Government to include the public lands of the South Castle area in a World Heritage Site nomination.

AWA outlined the concept of a Waterton/Glacier Biosphere Zone of Cooperation adjoining the national parks and including both public and private lands. This "zone of cooperation" would extend some 29 km northward from the Waterton Park north boundary to encompass Whitney Creek and adjoining valleys. This zone was viewed as a critical buffer area aimed at protecting wildlife species that appear to be experiencing serious stress within the small remaining wildlife habitat available in Waterton Park. Alluding to possible provincial support for the biosphere protection concept, the AWA noted that at one time most of the South Castle region including the Front Ranges was included in a provincial park reserve. However, it acknowledged that in the last several years the Front Range portion which includes much of the Waterton Field had been deleted from the proposed provincial park.

(b) Views of Shell

For the Whitney Creek area, Shell stressed that the IRP provides for multiple uses including gas step-out wells subject to suitable environmental protection measures.

Referring to the biosphere concept in general, Shell observed that the province had given only limited official support to the UNESCO initiatives outlined by AWA. In addition, a provincial park extending north from Waterton Park and including Whitney Creek appeared to be an outdated idea that was superseded by the 1985 South Castle IRP and a recent initiative to establish provincial park reserve lands on the West

Castle River some distance west of Whitney Creek. While not taking issue with the notion of the wildlife biosphere phenomena, Shell referred to the IRP as the operative land management document forming the basis for addressing wildlife management.

(c) Views of the Board

The Board sees wide agreement by all participants in the proceeding that the biosphere concept is a valid approach to dealing with wildlife management issues. Local ecological systems like Whitney Creek basin merge into larger ecological zones and these ultimately link up to describe enlarged biosphere regions. The Board regards the long-range aim for reclamation and return of the existing Waterton Field to a form of biosphere protection area to be consistent with the basic objectives, including permitted land uses, prescribed in the IRP. Indeed, the land use mosaic and the objectives set out in the IRP offer clear possibilities for achieving self-sustaining biosphere protection. No international or national directives are needed to pursue these objectives. Indeed, the Board sees the IRP guidelines as placing the onus on all land users, industry, agriculture, recreation, and tourism businesses, of meeting an obligation commensurate with their respective degree of use to foster and support enduring biosphere protection. For this to be achieved, a process of co-operative action by major land users such as Shell, and the many other lesser land users, must be actively pursued to assure realization of the common long-range objective outlined by the AWA.

7.2 Impacts on Wildlife

(a) Views of Shell

Shell stated in its environmental overview that the wildlife in Whitney Creek basin will experience minor to moderate impacts if the 6-30 development proceeds. Shell based this conclusion on the premise that the scale and duration of the project are not sufficient to threaten wildlife, at least at the population level. Given the anticipated minor disruptive impacts on wildlife, Shell did not consider it necessary to carefully control construction periods, or to monitor any specific species before or during the construction and producing life of the well. During the hearing, however, Shell produced an evaluation of the grizzly bear habitat along the route of the access road, which suggested some minor alignment changes could avoid certain areas of riparian habitat.

(b) Views of the Interveners

The AWA stated that the Whitney Creek basin is an area known to harbour several species which are dependent on the wildland character of the area to varying extent. Elk and grizzly, as well as possibly wolverine

and cougar, are known to be present or travelling in the area. Concerns for wildlife expressed during the hearing were:

- o loss of critical habitat use forcing wildlife to search for other areas, the effect being increased energy requirements, stress, and possible mortality,
- o increased mortality from legal and illegal hunting which would result from easier road access,
- o an overall lack of site-specific data respecting population dynamics and range,
- o the potential cumulative impact of several wells on the Whitney Creek ecosystem.

The AWA maintained that inadequate data are available on which to decide the potential degree of disruption on the wildlife. It was noted that the province-wide reduction in elk use of habitat and elk population had spurred FLW to reduce the opportunity for 1988 elk hunting. AWA surmised that intrusion into Whitney Creek wildlands may ultimately adversely affect regional elk populations. For example, AWA contended that general deterioration in regional elk population can be correlated rather directly with the onset and development of the wells now present in the Waterton gas field. AWA concluded that Shell's proposal was at cross-purposes to the province's elk population goals, and that no further habitat loss can be accepted if the elk population is to be maintained or increased.

Dr. C. Jonkel appeared as an expert witness for the AWA, and spoke to the status of grizzly bears in the Whitney Creek region. The range of bear movements would likely encompass several of the undeveloped valleys in the South Castle region, as well as land in Waterton National Park. The Whitney Creek basin offers at least some vital habitat components such as spring range and cover. Dr. Jonkel expressed concern about the lack of up-to-date bear population data on which to base decisions and mitigative measures and suggested that development should not proceed until data relating to Whitney Creek are available. Responding to questions from the Board, Dr. Jonkel suggested that the responsibility for this data collection would fall primarily with the provincial agencies, though funding could conceivably be provided from several sources.

Diamond Hitch attested to the value of Whitney Creek as a sanctuary for elk during the latter part of the hunting season, although evidence submitted shows declining presence in the area for the past 8 years. Mr. Judd believed that hunting pressure forces the elk into the Whitney Creek basin where there is adequate cover in which to avoid harassment.

Diamond Hitch and the AWA presented Mr. Gary Hornbeck as a joint witness on the potential impact of the proposed development on the elk population. Mr. Hornbeck stated that management of elk is impossible without knowledge of the effects that industrial development has on the small remaining elk ranges in southwestern Alberta. He suggested that the environmental overview provided by Shell may be useful for providing guidelines for investigation, but is not an actual measurement of the habitat and security needs of the elk that may be using the Whitney Creek basin. He said that an informed picture of elk populations including spring, summer, and winter range would be required in order to devise effective compensatory management programs.

Mr. Hornbeck concluded that a 3- to 5-year baseline research program was required to determine the proper management options for the elk using the Whitney Creek basin. A suitable number of elk should be radio tagged and their behaviour closely observed and recorded in relation to range and security requirements.

Dr. Sheppard, speaking as an experienced wildlife researcher as well as a local resident, opposed the application on the basis of a lack of credible wildlife population data. He expressed concern about the long-term effect on wildlife as a result of gradual industrial expansion into their habitat. He said that detailed studies of the impact of regional gas development on fish and wildlife are long overdue. Dr. Sheppard challenged the statements in Shell's environmental overview that the number of elk at risk is small, alternatives are available, and the effect will be temporary.

Dr. Sheppard presented a record of wildlife observation made from his home some miles away and dating back to 1981 to indicate that there has been a continuing population decline in various ungulate species. Although he initially attributed the cause to pipeline construction activity, Dr. Sheppard agreed that climatic conditions may also contribute to the variance in sightings and that a systematic study of wildlife would be needed to determine the reasons for population reduction.

Mrs. Marble, speaking for the National Audubon Society (the Society), spoke of how wildlife uses biological boundaries rather than political boundaries such as parks. She emphasized the wildlife sanctuary aspect of the Whitney Creek basin and specifically mentioned the concerns of the Society for grizzly bears which move freely over international boundaries.

The Lethbridge Fish and Game Association (the Association) concerns for preservation and conservation of all wildlife were stated by Mr. Rollie Stewart. The Association chose not to take a position on the

application before the Board but asked that the Board consider all the evidence presented during the hearing.

Mr. Wolf mentioned his particular concern for wildlife habitat and how various industrial incursions had degraded and reduced wildlife populations.

(c) Views of the Board

Both the applicant and interveners presented expert opinion concerning the possible impacts on wildlife, both in the near-term construction/drilling phase and in the long-term production phase. The Board understands that there was general recognition by the experts that potential impacts during the construction/drilling phase could be moderately high. Opinion was divided concerning the possible effects of low-level but regular encounters that could continue through the 20 years of production operations. AWA/Diamond Hitch's opinion is that examples elsewhere in the eastern slopes demonstrate that elk may abandon the area under such conditions. Shell's expert opinion is not altogether clear on this point, but the Board interprets its view to be that compensatory elk enhancement programs could be instituted if permanent disruption occurred. Given the reduced sightings, it is quite likely that the presence of elk is limited and the prolonged impact would be manageable.

In addition to the problem of disruptions and chronic minor encounters, the AWA raised concerns about loss of critical habitat. For purposes of this discussion, the Board has interpreted "loss of critical habitat" to mean the loss of habitation resulting from physical changes to an ecosystem or wildlife being driven out of an area by intruding forces. Shell's bear habitat experts seemed to agree that the lower reaches of the road could cause some loss of riparian habitat. A possible opposite outcome is that a reclaimed, revegetated roadside corridor would provide enhanced habitat for elk. On balance, considering that possibly only 4 or 5 hectares of land surface would be taken up for non-vegetated road and well-site surfaces, the Board doubts that loss of physical habitat would itself be cause for concern about loss of critical habitat.

The key issue therefore appears to centre on the impacts resulting from wildlife disturbance and whether or not permanent disruption, for example, abandonment of the area by certain species such as elk, would result. AWA and Diamond Hitch proposed that the 6-30 well development be denied for now and that wildlife in the area be carefully monitored over the next 3 to 5 years. This would enhance the judgement on the impact of the 6-30 well, and also assist in design of mitigative measures and compensatory wildlife enhancement programs. In principle, the Board agrees with this and would agree with the idea of developing a solid knowledge base respecting wildlife usage of the Whitney Creek drainage basin. However, testimony indicated that none of the wildlife species of concern, these being elk, grizzly bear, wolverine, and

cougar, are considered endangered species at this time. The Board believes that the impact on habitat use in this case may have a close relationship between the seasonal time and the development of the resources. This may in fact be more significant than the actual development. The Board therefore believes that studies focused on defining periods of use and non-use of the area by wildlife would be very beneficial. In that respect, the Board would not consider availability of the studies an absolute necessity to a decision on the 6-30 well, although careful consideration should be given to a construction schedule. By the same token, the Board recognizes the problem of the loss by wildlife of access to critical habitat, and its implications for gradual deterioration of biological diversity within a local wildlife populace. In this respect, long-term continuing studies might prove especially useful in the development of compensatory enhancement programs.

7.3 Fisheries

(a) Views of Shell

Shell's environmental overview stated that enough is known of the distribution and life history of trout to ensure that construction activities will result in only negligible impacts. The three creek crossings for the road have been approved by FLW and a high-integrity channel bank reconstruction is a requirement of the MSL. Ongoing scrutiny by FLW will occur during road construction. Shell has proposed several measures to protect Whitney Creek from excessive siltation and possible stream damage, including:

- minimizing land clearing and avoiding sensitive terrain,
- planning special measures to stabilize critical slopes,
- effective surface drainage containment,
- proper selection of stream crossing sites to avoid unstable channels,
- use of steel span bridges,
- channel bank reconstruction in certain areas,
- proper storage, use, and disposal of potential stream pollutants.

(b) Views of the Interveners

Mr. D. Mayhood appeared as an expert witness for the AWA regarding fisheries and based his views on studies he conducted of the Whitney Creek trout population and stream bed condition during July of 1988. His results indicate that stream bed siltation that may be caused by Shell's proposed road and well-site construction is potentially the most serious adverse impact on fish habitat.

The study concluded that the consequences of siltation on the resident fish population could be profound, including reduced spawning success, reduced food supplies, filled-in over-wintering pools, loss of cover for juveniles, and generally reduced carrying capacity of the stream.

Mr. Mayhood stated that Whitney Creek holds a significant trout population and added that the critical trout habitat in Whitney Creek is already measurably degraded by both natural and man-made impacts. Mr. Mayhood also believed that it would be useful to know where the spawning sites are so that we would then know how the sites would be affected by any increased sedimentation and siltation. This work has not been done by Shell, and Mr. Mayhood recommended that this kind of work ought to be done by the applicant in order to justify statements of negligible impact.

(c) Views of the Board

The Board is confident that Shell, through careful control of its construction activity, could build and maintain the proposed road, creek crossings, and well site in such a way that stream bed siltation from those sources could be avoided.

Nonethless, the Board recognizes Mr. Mayhood's 1988 study as a valuable baseline to development of a fisheries habitat enhancement program for Whitney Creek. The Board acknowledges that further studies to identify spawning sites and develop desiltation structures and enhanced fisheries habitat would be beneficial. The Board believes that any such programs would be a logical outcome consistent with the expressed highest priority of the Castle River Sub-Regional IRP, namely watershed protection.

7.4 Vegetation and Land Reclamation

(a) Views of Shell

The environmental overview that Shell provided with the application stated that sufficient botanical information is available upon which to base mitigative measures in the construction and operation of the road and well site. The overview also concluded that there will be no major impacts on the vegetation existing in the Whitney Creek basin.

At the hearing, Shell submitted a report summarizing three rare plant surveys which had been conducted over the summer of 1988. The report concluded that five or possibly six rare plant species existed in the Whitney Creek basin. Given that the habitat of these rare plants is not unique or uncommon, and that there is evidence that these species have additional habitat available in the valleys adjacent to the study area, as well as regions in southwestern Alberta, the report concluded that it is not likely that development and use of the proposed well site and road will endanger the population of these species as it exists in Alberta. Even though the 6-30 well development would only affect small numbers of rare plants, the report cautioned about cumulative effects of possibly several more roads and well sites in the basin. The rare plant survey also recommended that Shell include a detailed habitat assessment in its predevelopment study.

(b) Views of the Interveners

The Federation of Alberta Naturalists cautioned that native plant communities should be protected from the possibility of introduced non-native plants. In that vein, the Federation appealed for the possible use of native plants for erosion control of road and well-site side slopes, rather than using introduced non-native grass mixes.

The Public Advisory Committees focused on the question of vegetation to be used for reclamation. During questioning by the Board, the Public Advisory Committees suggested that reclamation plans and procedures should be formally inspected and reported on from initial construction, during lifetime use, and during abandonment and reclamation. The intent would be to have formally documented records similar to those for major regulated operations for which Alberta Environment administers Development and Reclamation Approvals.

The AWA stated that the loss of any of the rare plants mentioned in Shell's botanical study would be significant and noted that the Shell study cautioned against the incremental impacts of several well sites and access roads.

(c) Views of the Board

The Board notes that the MSL provides for specific measures to protect sensitive areas, especially stream crossings, and employment of construction procedures to ensure topsoil recovery and to minimize impacts on adjacent areas. The Board is confident, on the basis of the undertakings proposed by Shell and the monitoring of those activities by FLW, that road and well-site construction impacts will be managed in a very sound manner.

The Public Advisory Committees and the Federation of Alberta Naturalists both expressed concerns and interest in procedures that would ensure environmental integrity of roads and well-site areas, and effective reclamation of those sites at abandonment, considering that topsoil may have to be stored for 20 years or more. The Board observes that the MSL issued to Shell for this location includes specific conditions which would facilitate the proper reclamation of the road and well-site area. As an implicit part of the MSL, the forestry officer undertakes a frequent inspection program for compliance which should ensure a reliable soils preservation program.

8 NEED FOR AN ONGOING CONSULTATIVE PROCESS

As a rule, the Board endeavours to foster good communications between applicants for resource developments and all interested parties that may be affected by that development. The Board believes that through direct consultation, all parties will appreciate the factors influencing the development, including construction, and a modicum of agreement may be

reached regarding the nature of environmental impacts and possible mitigation measures that could be applied on an ongoing basis to minimize such impacts.

In this instance, Shell filed its well licence application for the 6-30 well in July 1987 but no active consideration of the application was initiated until the late fall. The Board encouraged Shell to communicate with AWA and others that might have concerns respecting environmental impacts associated with the proposed development. In that connection, though it already had received the MSL for the road and well site, Shell launched an environmental overview study through its consultant, R. Webb Environmental Services Ltd. Further consultation with AWA and others ensued and the environmental overview was eventually made available to AWA and others in March 1988. Disagreement continued, and as a result, in April 1988 the Board made arrangements for the hearing.

In retrospect it seems clear that all the concerns could have been more efficiently addressed through a continuation of the consultative process rather than through the hearing process. The environmental overview filed by Shell, plus evidence and perspectives concerning the environment subsequently brought forward by AWA, Diamond Hitch, Federation of Alberta Naturalists, Public Advisory Committees, and others, could have been readily taken up and thoroughly assessed in a consultative process.

The Board intends to initiate a forum where this can be done in an effective manner at the earliest convenient date.

9 FINDINGS AND CONCLUSIONS

The Board has considered all of the evidence related to this application and finds that:

- o The lands in question are subject to the South Castle Sub-Regional Integrated Resource Plan approved by the Alberta Government in 1985 and managed by Forestry, Lands and Wildlife.

- o The lands in the upper Whitney Creek basin are classified as "Zone 5: Multiple Use" which includes petroleum and natural gas step-out wells if it can be demonstrated that the high recreation value of the resource management area can be maintained.

- o Under the IRP, the Whitney Creek basin is part of a management area for which the primary intent is protection of the watershed and wildland, recreation character.

- o On 16 and 23 July 1987, FLW issued an MSL to provide lands for an access road, utility corridor, and well site. The primary focus of the 26 specific conditions named in the MSL was to control the construction activities and reclamation requirements. Other

measures were to ensure protection of stream crossings and a requirement that active consultation with the local FLW officer should take place to avoid undue impacts on the creek bed.

- Upon filing its 6-30 well licence application with the ERCB, the Board encouraged Shell to discuss the impact of the well with interested parties, including the AWA, in the hope of resolving any outstanding concerns. The ERCB did this on the basis that the AWA had consistently expressed a strong interest in protecting the wildland character of the undeveloped features in the region and in the belief that a consultative, problem-solving approach would lead to better long-range accommodation of concerns respecting surface and subsurface resources.

- Shell retained an environmental consultant (R. Webb Environmental Services Ltd.) to prepare an environmental overview endeavouring to assess the potential impacts of the proposed well, access road, utility corridor and well site in relation to the existing environmental setting. That report was released, made available, and discussed with interested parties in March 1988.

- Shell submitted that the proposed well was necessary to exploit the trapped resources in Sheets IIIb and IVc of the existing Waterton Field and the proposed 6-30 well site was the only technical and environmentally suitable surface location.

- Shell initially believed that all appropriate environmental protection measures would be enforced by FLW and that further review of these by the Board was not warranted.

- Diamond Hitch and AWA believed that the mineral surface lease had been issued on a rather narrow proposition of mitigation of impacts and argued that an in-depth Environmental Impact Assessment (EIA) was necessary to evaluate if the well location was environmentally acceptable. They concluded that such a study should include an extensive inventory of flora, fauna, and aesthetic resources as well as an overall measure of wildland values of the basin.

- The AWA and others also argued that ecological systems are interactive and subsets of a biosphere cannot be isolated to measure impacts of a local intrusion. With comprehensive environmental information in hand they believed that long-range wildland values and impacts related to the well site and road intrusion could be properly compared with the potential economic benefits of production of the gas resource.

The Board believes that the IRP provides the broad land use framework for consideration of the proposed developments. The IRP makes specific reference to the need to protect watershed and wildland recreational character of the upper Whitney Creek area. The Board believes that

emphasis on these resources was a clear recognition by the Government that attractive features of this sub-alpine valley with the surrounding mountain backdrop warranted specific protection measures. As well, from the evidence before it the Board further concludes that careful preservation of the area was a key objective of the IRP.

The Board is satisfied that it is within its mandate, as argued by Diamond Hitch, to assess all aspects of the application before it, including technical, economic, and environmental, and to decide either to approve, with or without conditions, or deny the well licence application.

The Board is satisfied, on the basis of the evidence before it, that a large natural gas resource probably lies entrapped in the IIIb and IVc thrustfold geological structure identified and described by Shell. Based upon the evidence, some 1000 to 1300 x 10^6 m^3 of recoverable reserves are contained in each section or DSU in the area. Considering the prospects of pool extensions if the proposed 6-30 well is successful, the Board concludes that some 1000 x 10^6 to 4000 x 10^6 m^3 of new gas would be recovered if the development were to proceed. Nominal estimates put forward by Shell indicate the value of the resource to be upwards of 135 million dollars per section of land of which the Crown's royalty share would be some 30 million dollars per section.

The Board is satisfied that the only practical and safe means of drilling the 6-30 well is from a location somewhere in close proximity to the 2-25-4-2 site chosen by Shell. Shell's evidence was that, if the applied-for 6-30 well achieved its geological objectives so as to encourage further development, ultimately three more wells may be required to effectively drain the structure. However, those would have to be weighed at the time the licences were applied for.

The Board acknowledges that protection of the watershed and wildland recreation values is a prominent objective of the IRP. It further seems apparent that these values will increase in importance with time as tourism industries gradually supplant resource extraction industries. The Board also notes that the 6-30 well would be located in Zone 5 Multiple Use lands but that the well is in close proximity to adjoining Zone 1 Prime Protection lands. It is therefore evident that extraordinary care would have to be exercised to protect the watershed and wildland character in connection with any step-out well developments in this sub-alpine valley.

The evidence brought both by Shell and Diamond Hitch reveals a problem regarding commercial guides intending to continue to use the upper Whitney Creek basin as a wilderness experience, if well development proceeds. The Board is neither capable of properly assessing the

options in this regard nor would it have the mandate to ensure that Diamond Hitch's objectives were accommodated in future even if the well licence were denied.

Regarding the desires of "soft" recreational users of the area, the Board believes that strategic location of the lower bridge and locked gate entering the basin would provide FLW with a means of controlled access, including possible exclusion of all-terrain vehicles. This would seem to be an improved form of wildland recreation protection compared to the existing situation.

The Board notes that there is wide agreement among wildlife experts concerning the biosphere system concept. The upper Whitney Creek basin is a local ecological area which has linkages to adjacent areas which in turn combine into a larger biosphere region. In fact, the IRP concept relies on that same concept and endeavours to promote protection as necessary with due regard for the economic needs and desires of society. The evidence brought forward at the hearing indicated that, though there was a deep concern respecting loss of critical habitat and wildlife sanctuary believed to be presently available in the Whitney Creek basin, at the same time the species that might be displaced by the 6-30 well intrusion were not on the endangered species list at this time. The Board therefore concludes that it would not seem to be in the public interest to defer proceeding with the 6-30 well for another 3 to 5 years merely for the reason of obtaining further wildlife inventory studies. On the contrary, such delay would seriously disadvantage Shell in its objective of orderly and timely depletion of the Waterton gas resources and during that period of time, would also deprive local businesses from sharing in the economic benefits of such developments. As an incidental matter, the Board recognizes that during continuation of the gas surplus situation the Crown's income from royalties and taxes would be essentially unaffected by the proposed 3- to 5-year delay.

The foregoing notwithstanding, the Board recognizes that "nickel and dime" encroachments into wildland areas do have the potential of ultimately depriving wildlife of access to critical habitat. It is in this regard that the Board is convinced that, even where well developments are allowed to proceed, continuing comprehensive studies to assess ecosystem effects and the need for alternative environmental enhancement programs should be conducted. The Board views the matter of fisheries, protection of watershed quality, protection of vegetation, and management of long-range development and reclamation with the same attitude. The Board also notes that much information has already been assembled by Shell, AWA, Diamond Hitch, and others that can be put to use in any such program. As previously noted, the Board believes that timing and access of using the area for road construction and drilling should be considered in the consultative process to protect habitat use.

The Board believes the best way to carry out such programs of environmental monitoring is through a consultative process that would involve prime leadership by FLW but include industry and other key participants.

In summary, the Board finds, in connection with the specific questions posed by Diamond Hitch and the criteria that the Board considers pertinent to approval or denial of a well licence application, that:

- The well would not pose a serious hazard to the public.

- The only technically suitable and safe surface locations for accessing the gas resources is from the approximate location chosen by the applicant.

- An alternative surface location is not available which would significantly reduce the impact on the surface.

- The potential economic benefits of the 6-30 development would be very large, mounting into tens of millions of dollars.

- Economic costs through alteration of wildland recreation value of the upper Whitney Creek basin, though not quantified, may be rather significant in the near term, but following land reclamation and revegetation should eventually become imperceptible. This is a key objective of the IRP.

- A program of carefully timed and managed access for construction, drilling, testing, and completion must be put into effect in order to ensure reliable watershed protection and to promote optimum preservation of wildlife and wildland recreation values. Further, in this regard:

  - The continuation of the stream evaluation initiated by Mr. Mayhood would benefit the overall concept of watershed protection which is of utmost priority within the terms of the IRP.

  - It may be appropriate to examine the alignment of the proposed access road to avoid areas of valuable riparian habitat as suggested by Shell's bear consultant recognizing that this is a matter within the jurisdiction of FLW.

  - Shell's botanical consultant suggested that in the context of continued expansion of drilling activities in the area, a detailed habitat assessment should be performed.

  - An environmental monitoring program should be established to evaluate, over a period of years, ecosystem phenomena and the need for alternative environmental enhancement programs to offset the cumulative impacts of well development encroachments.

10 DECISION

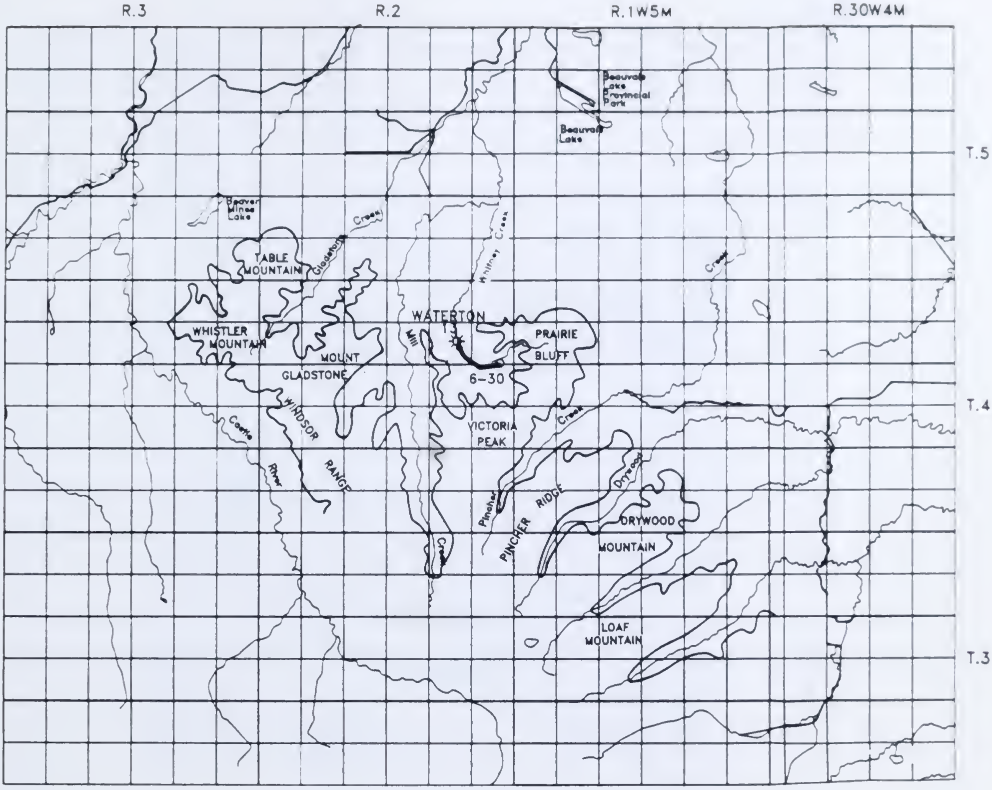
The Board is satisfied that it is in the public interest that the 6-30 well proceed and, accordingly, the Board approves the application in accordance with this report. Prior to a licence being issued, Shell must submit and receive approval from the Board of the Emergency Response Plan. Furthermore, the Board will arrange consultation with Shell, FLW, and interested parties concerning measures, in addition to those already enunciated in the mineral surface lease, aimed at furthering the primary objectives of the Castle River Integrated Resource Plan as it applies to the lands affected. Specifically, attention would be given to promoting preservation and protection of aesthetic and wildlife resources and wildland recreation values of the sub-alpine upper Whitney Creek basin.

DATED at Calgary, Alberta, on 22 December 1988.

N. A. Strom, P.Eng.
Vice Chairman

F. J. Mink, P.Eng.
Board Member

E. G. Fox, P.Eng.
Acting Board Member



Q Proposed well

Roads

5000 ft Contour

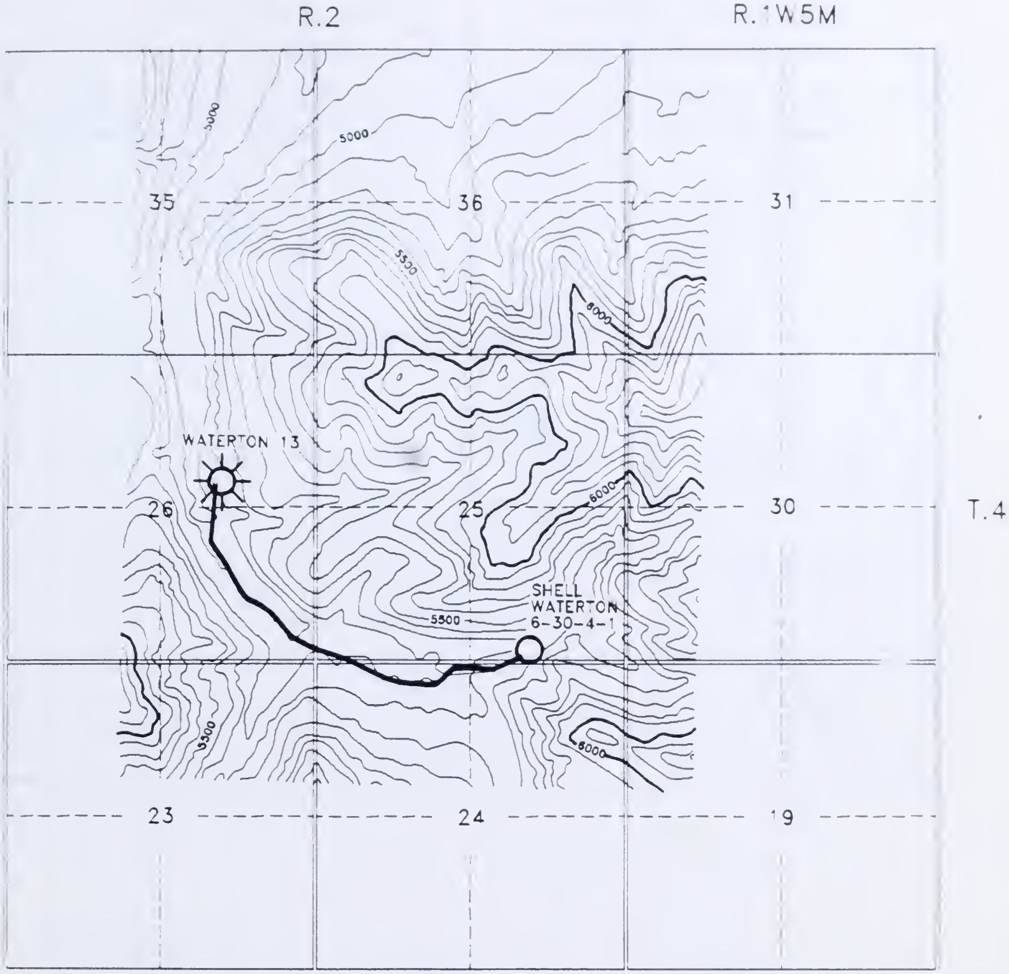
Access Road

Hydrography

Application No. 880557

Shell Waterton 6-30-4-1 (Surface location 2-25-4-2W5M)

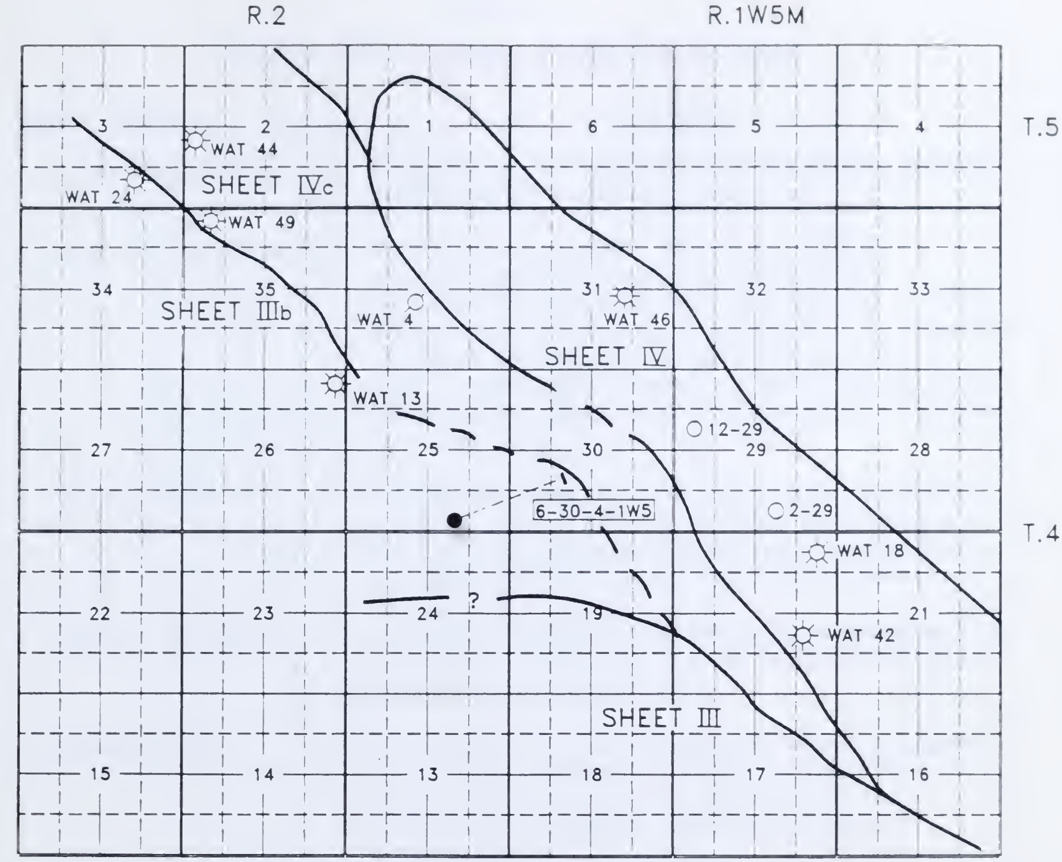
FIGURE 1: WATERTON AREA



Application No. 880557

Shell Waterton 6-30-4-1 (Surface location 2-25-4-2W5M)

FIGURE 2 : WATERTON AREA



Suspended Well

Gas Well

Licensed Well (approximate sub-surface location)

Proposed well, surface location 2–25, subsurface location 6–30

Shell's approximate Sheet Edges (adapted to this figure)

Application No. 880557

FIGURE 3 : WATERTON AREA WELL LOCATIONS AND APPROXIMATE SHEET EDGES

Table 1

INTENTS OF THE EASTERN SLOPES POLICY ZONES

Zone	Title	INTENT
1	Prime Protection	To preserve environmentally sensitive terrain and valuable aesthetic resources.
2	Critical Wildlife	To protect specific fish and wildlife populations by protecting aquatic and terrestrial habitats that are crucial to the maintenance of those populations. This zoning designation recognizes only those habitat areas, which are crucial to the life cycle of particular species due to vegetation, climate or topography.
3	Special Use*	To recognize historical resources, scientific research areas and lands which have unique management requirements or legislative status or which can not be accommodated elsewhere.
4	General Recreation	To retain a variety of natural environments to serve as a focus for a wide range of outdoor recreational activities.
5	Multiple Use	To provide for the management and development of the full range of available resources, while meeting long-term objectives for watershed management and environmental protection.
6	Agriculture*	To designate lands which are currently utilized or are considered suitable for cultivation or improved grazing.
7	Industrial*	To recognize existing or approved industrial operations.
8	Facility	To recognize existing or approved settlement and commercial development areas.

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* Not applied in the Castle River area.

Extracted from Castle River Sub-Regional Integrated Resource Plan, 1985, Edmonton. ENR Technical Report No. T/1 - No. 12, page 22.

TABLE 2

ACTIVITY \ ZONE	1 PRIME PROTECTION	2 CRITICAL WILDLIFE	3 SPECIAL USE	4 GENERAL RECREATION	5 MULTIPLE USE	6 AGRICULTURE	7 INDUSTRIAL	8 FACILITY
Non- motorized recreation	Compatible	Compatible	Permitted	Compatible	Compatible	Compatible	Permitted	Compatible
Fishing	Compatible	Compatible	Permitted	Compatible	Compatible	Compatible	Permitted	Compatible
Hunting	Compatible	Compatible	Permitted	Permitted	Compatible	Compatible	Permitted	Not Permitted
Scientific study	Compatible	Permitted	Permitted	Permitted	Compatible	Compatible	Compatible	Compatible
Trapping	Compatible	Permitted	Permitted	Permitted	Compatible	Compatible	Not Permitted	Not Permitted
Trails,non-motorized	Permitted	Permitted	Permitted	Compatible	Compatible	Compatible	Permitted	Compatible
Transportation & utility corridors	Permitted	Permitted	Permitted	Permitted	Compatible	Compatible	Compatible	Compatible
Primitive camping	Permitted	Permitted	Permitted	Compatible	Compatible	Compatible	Not Permitted	Not Permitted
Intensive recreation	Permitted	Not Permitted	Permitted	Compatible	Compatible	Permitted	Permitted	Compatible
Off highway vehicle activity	Not Permitted	Permitted	Permitted	Permitted	Compatible	Compatible	Compatible	Compatible
Logging	Not Permitted	Permitted	Permitted	Permitted	Compatible	Compatible	Compatible	Permitted
Domestic grazing	Not Permitted	Permitted	Permitted	Permitted	Compatible	Compatible	Not Permitted	Permitted
Petroleum and natural gas exploration & development	Not Permitted	Permitted	Permitted	Permitted	Compatible	Compatible	Compatible	Permitted
Coal exploration & development	Not Permitted	Permitted	Permitted	Permitted	Compatible	Compatible	Compatible	Not Permitted
Mineral exploration & development	Not Permitted	Permitted	Permitted	Permitted	Compatible	Compatible	Compatible	Not Permitted
Serviced camping	Not Permitted	Permitted	Permitted	Compatible	Compatible	Permitted	Permitted	Compatible
Commercial development	Not Permitted	Not Permitted	Permitted	Permitted	Permitted	Permitted	Permitted	Compatible
Industrial development	Not Permitted	Not Permitted	Permitted	Not Permitted	Compatible	Permitted	Compatible	Permitted
Residential subdivisions	Not Permitted	Not Permitted	Permitted	Permitted	Permitted	Compatible	Permitted	Compatible
Cultivation	Not Permitted	Not Permitted	Permitted	Not Permitted	Permitted	Compatible	Permitted	Permitted

Compatible use — Uses that are considered to be compatible with the intent of a land use zone normal guidelines and land use regulations.

Permitted use — Uses that may be compatible with the intent of a land use zone under certain circumstances and under special conditions and controls where necessary. •

Not Permitted Use — Uses that are not compatible with the intent or capabilities of a land use zone.

These activities are only representative of the range of activities that occur in the Eastern Slopes. For these and any other activities, the possibility of whether they should or should not take place in a particular area must always be measured against the fundamental management intentions for that zone. Since economic opportunities are not all known in advance, site-specified developments may be considered for any zone

• Extracted from Castle River Sub-Regional Integrated Resource Plan 1985, Edmonton. ENR Technical Report No. T/1-No.12, page 21

D 88-16

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

GAS REMOVAL PERMIT AMENDMENT
PAN-ALBERTA GAS LTD.

Decision D 88-17
Application 870705

1 INTRODUCTION

1.1 Application

Pan-Alberta Gas Ltd. (Pan-Alberta) applied to the Energy Resources Conservation Board (Board or ERCB) under the Gas Resources Preservation Act to amend the gas removal permit resulting from the consolidation of existing Permits PA 85-1 and PA 85-2. Pan-Alberta's Application 871693 to consolidate the two permits was granted by means of Permit GR 87-236, issued on 29 March 1988. The applicant requested amendments which would

- extend the term of the existing permit that ends on 31 October 1997 by a further 15 years so as to end on 31 October 2012,
- add an incremental volume of gas permitted for removal of 37.698 billion cubic metres (10^9 m^3), increasing the total volume of gas permitted for removal to 230.998 x 10^9 m^3 or, after accounting for removals to 31 December 1987 using ERCB records, a remaining volume for removals of 188.8 x 10^9 m^3,
- maintain the annual maximum volume of gas permitted for removal at the existing total of 19.918 x 10^9 m^3 until 31 October 1997, then reduce it to 2.513 x 10^9 m^3 for the remainder of the term of the permit, and
- maintain the daily maximum volume of gas permitted for removal at the existing total of 61.171 million (10^6) m^3 until 31 October 1997, then reduce it to 7.479 x 10^6 m^3 for the remainder of the term of the permit.

The gas to be removed from Alberta under the requested amended permit would be delivered by NOVA Corporation of Alberta (NOVA) to Northwest Alaskan Pipeline Company for resale to Pacific Interstate Transmission Company at the international boundary. The latter company would in turn sell the gas to Southern California Gas Company at the state border to serve customers in southern California.

1.2 Hearing

The application was considered at a public hearing in Calgary, Alberta, on 16 and 17 March 1988, before a panel consisting of N. A. Strom, P.Eng., F. J. Mink, P.Eng., and J. P. Prince, Ph.D. Those who appeared at the hearing and abbreviations used in the report are listed in Appendix A.

1.3 Interventions

Submissions were filed in response to the notice of hearing of the subject application by 14 parties. Of these, 11 appeared at the hearing; 3 parties, Foothills Pipe Lines, Pacific Interstate, and SoCal supported the application; while 2 parties, Vector and WGML, raised concerns with respect to the application.

2 ISSUES

The Board considers the issues to be

- the total gas reserves available for removal from Alberta,
- the established gas reserves under Pan-Alberta control,
- access to transportation,
- the Alberta public interest, and
- the permit term and maximum daily and annual permit volumes.

3 GAS RESERVES AVAILABLE FOR REMOVAL FROM ALBERTA

3.1 Views of Pan-Alberta

Pan-Alberta submitted that its proposal would not result in inadequate supplies to Alberta consumers in future. It noted that the Board's report regarding gas supply protection for Alberta, Report 87-A, states that some 275.0×10^9 m^3 of gas was surplus to Alberta's requirements as prescribed under its protection policy. As Pan-Alberta applied to remove only an additional 37.698×10^9 m^3 of gas over the proposed extended life of the permit, the remaining gas is clearly surplus to the present and future needs of users in Alberta. Further, Pan-Alberta was optimistic that more reserves would be developed in Alberta to replace those removed. It concluded that it had met the requirements of public policy with respect to the protection of gas supplies for Alberta consumers.

3.2 Views of the Board

As shown in Table 1 below, as of 31 December 1987 a surplus of 190×10^9 m^3 of gas was available for permits after accounting for existing permits, Alberta core requirements, and other industrial contracted requirements. Therefore, the approval of Pan-Alberta's request for a permit to remove an additional 37.698×10^9 m^3 of gas would leave some 152×10^9 m^3 of gas available for permitting. On that basis, the Board is satisfied that there are ample reserves available to grant Pan-Alberta's application.

TABLE 1 BOARD ESTIMATE OF GAS RESERVES AVAILABLE FOR INCLUSION IN PERMITS AS AT 31 DECEMBER 1987

	Year End 1987	
	10^9 m^3 at 37.4 MJ/m^3	TCF at 1000 Btu/ft^3
Reserves		
1. Total Remaining Established Reserves	1 714	60.8
Less:		
2. One-half of Reserves Beyond Economic Reach	29	1.0
3. One-half of Deferred Reserves	90	3.2
4. Total Available Reserves	1 595	56.6
Requirements		
Alberta Requirements		
5. Core Market Requirements	105	3.7
6. Contracted for Non-core Markets	66	2.3
7. Permit-related Fuel and Shrinkage	112	4.0
Permit Requirements		
8. Remaining Permit Commitments	1 122	39.8
9. Total Requirements	1 405	49.8
Available		
10. Available for Permits	190	6.8

4 RESERVES UNDER PAN-ALBERTA'S CONTROL

4.1 Views of Pan-Alberta

Pan-Alberta submitted that it had 224.098 x 10^9 m^3 of remaining gas reserves under contract as of 31 October 1987. Accounting for withdrawals during November and December 1987 under its Permit GR 87-236 of some 1.927 x 10^9 m^3 of gas, as recorded by the Board, results in a total remaining reserve under contract to 31 December 1987 of 222.171 x 10^9 m^3. Following questioning at the hearing which indicated that the Board staff differed significantly with Pan-Alberta regarding the interpretation of available reserves, the Board agreed to provide an additional opportunity for Pan-Alberta to discuss differences in reserves interpretation by means of a post-hearing technical meeting. A report of the meeting, held on 12 and 13 April 1988, is attached as Appendix B. As a result of the meeting, Pan-Alberta reduced its estimate of reserves by some 3.67 x 10^9 m^3, resulting in 218.501 x 10^9 m^3 of gas reserves as of 31 December 1987. The applicant stated that it had sufficient gas reserves to meet the terms of the amended permit. If, however, it saw in the future that the reserves committed to it would not meet its obligations, it would contract for additional supplies.

4.2 Views of the Interveners

WGML opposed any suggestion that the Board should grant a gas removal permit for any volume of gas which exceeds the amount of reserves which the applicant has under contract.

4.3 Views of the Board

The Board understands that the Board staff's estimate of the remaining marketable gas reserves under Pan-Alberta's control at year-end 1987 totalled 163 x 10^9 m^3. Taking into account the Examiner's recommendation set out in Appendix B to adjust upwards certain parts of the staff's estimates would provide an upper estimate of some 175 x 10^9 m^3. The Board has reviewed the range of the reserves estimates in light of the results of the post-hearing pool evaluations and is prepared to recognize that Pan-Alberta has some 167 x 10^9 m^3 of established reserves under its control.

The Board acknowledges that, as summarized in the table below, there is a significant difference between the Board's and Pan-Alberta's reserves estimates. The Board considers many of Pan-Alberta's reserves estimates to be based on excessively liberal interpretations of areal extent, net pay, and/or recovery factors and to involve potential rather than established reserves. Consistent with its long-standing practice, the Board holds the position that in order to assure that the reserves recognized in a removal permit are appropriate, those reserves must be established in the field and must not be of the prospective future potential type.

As of the end of 1987, Pan-Alberta's existing permit would allow it to remove 151.131 x 10^9 m^3 of gas. Subtracting that volume from the Board's estimate of the total reserves under Pan-Alberta's control would leave 15.869 x 10^9 m^3 of gas available for inclusion as additional gas in the proposed amendment to the permit, as illustrated in the following tabulation:

	Pan-Alberta	Board
Remaining marketable reserves under Pan-Alberta's control as of 31 December 1987, including post-hearing reserves revisions (10^9 m^3)	218.501	167.000
Remaining volumes of gas that may be removed from Alberta under Pan-Alberta's existing permit as of 31 December 1987 (10^9 m^3)	151.131	151.131
Pan-Alberta gas available for inclusion in the proposed amendment to the permit (10^9 m^3)	67.370	15.869
Pan-Alberta request for addition to volume permitted for approval (10^9 m^3)	37.698	37.698

WGML's position that removal permits should not exceed reserves under contract is consistent with the Board's current practice. However, the Board recognizes that this practice may not be appropriate in future and will consider the matter as part of a general review of removal permits as discussed in Section 7.

5 ACCESS TO TRANSPORTATION

5.1 Views of Pan-Alberta

Pan-Alberta noted that all of the transportation facilities required to move gas under the proposed amended permit are in place, including those in Alberta. It said that it had a firm transportation arrangement with NOVA for a delivery volume of 36.6 x 10^6 m^3 (1.3 x 10^9 cubic feet) and a receipt volume of 45.1 x 10^6 m^3 (1.6 x 10^9 cubic feet) of gas per day. The applicant emphasized that it has not at the present time contracted for more firm capacity than it requires to meet its sales. Further, if Pan-Alberta required more capacity in the NOVA system, it would have to apply to NOVA in the same manner as any other producer. The applicant assumed that NOVA would treat Pan-Alberta the same as any other party who requested transportation.

5.2 Views of the Interveners

Vector expressed the concern that NOVA, which owns more than 50 per cent of Pan-Alberta, has given Pan-Alberta favoured treatment over other parties. It contended that Pan-Alberta had obtained pipeline capacity which is 8.4 x 10^6 m^3 (300 x 10^6 cubic feet) per day in excess of what is used. In the meantime, other producers are unable to obtain capacity in some areas because most of that capacity has been committed to moving gas to export markets. Thus, in spite of the fact that there may be enough reserves to meet Alberta's needs, the transportation may not be available in certain areas to serve those requirements. Vector opposed the application, but recommended that, if it is approved, the resulting permit should contain a stipulation to allow intra-Alberta customers access to transportation for at least the volume over what Pan-Alberta requires to meet its market. Also, Vector recommended that a panel monitor Pan-Alberta and NOVA to guarantee that Pan-Alberta does not gain any advantage that is unavailable to other shippers by virtue of its relationship with NOVA.

5.3 Views of the Board

The Board agrees with Vector that transportation service within Alberta should be available on an equitable basis, but notes that service may differ according to the nature and term of the commitment made by those requiring transportation services. If the commercial arrangements under which transportation services are provided are deemed to be unfair, the matter should be raised with industry associations and the government. The Board does not believe that conditions on removal permits would be an appropriate way to address such issues.

6 THE ALBERTA PUBLIC INTEREST

6.1 Views of Pan-Alberta

Pan-Alberta submitted a cost benefit analysis indicating that there is a positive net social benefit to an extension of the permit term, even under the least favourable conditions. The analysis was designed to take into account the main uncertainties about the economic environment, including gas prices and the cost of finding and developing future gas supplies. Pan-Alberta submitted that there are two important characteristics of its application which work to enhance the net social benefit. The first is that the gas is sold to a stable, high-quality market: SoCal is the largest distributor of gas in the United States, serving over 4 million customers, and is committed to arranging for long-term supplies for its customers. SoCal has also demonstrated its commitment to serving its market with Canadian gas by purchasing gas supplied by Pan-Alberta at a 100 per cent load factor for the last 3 years or so. Moreover, there is a 60 per cent take or pay provision in Pan-Alberta's sales contract, and a continuing demand charge covering Canadian transportation costs, which ensure that gas will be taken at

high load factors in future. An additional component which makes the SoCal market a premium one is that the expected gas prices are favourable over the long term. The pricing scheme in place is market-sensitive and provides for a semi-annual adjustment of the commodity charge component of the export price. The scheme ensures that the total cost of delivered gas under the contract will never be less than the weighted average cost of gas supplied to the southern California market by other suppliers. The second characteristic of Pan-Alberta's arrangement that enhances its net social benefit is that the reserves and facilities necessary to effect the additional exports are already in place and hence the incremental production and transportation costs are small. Pan-Alberta concluded that the applied-for amendments of its gas removal permit should produce a substantial on-going benefit to Alberta and therefore should be approved.

6.2 Views of the Interveners

Foothills Pipe Lines noted that it has a direct interest in, and supports, Pan-Alberta's application in that it provides transportation for the Pan-Alberta gas moving to export markets and has agreed to extend the term of Pan-Alberta's transportation contract to correspond with the term of the amended gas removal permit. Foothills Pipe Lines submitted that Alberta producers have already obtained significant benefits from Pan-Alberta's sales to the SoCal market, and should continue to do so. Foothills Pipe Lines stated that, should Pan-Alberta obtain the required regulatory approvals for the extension of its permit term, Foothills Pipe Lines would undertake a review of depreciation provisions of its contracts with a view to eliminating the need for the depreciation basket clause on the western leg of the pre-build system.

SoCal and Pacific Interstate supported Pan-Alberta's application. They noted that the requested extension of the permit period applied to a contract that has already proven to be beneficial to both Canadian suppliers and California consumers. Approval of the application would allow Pan-Alberta the opportunity, which may not exist in the future, to continue to serve a large and growing market in California. Further, transportation for the gas volumes involved is in place, and producers in Alberta support the proposed sale.

Vector indicated that the requested amended permit would be expected to have an economic benefit to Alberta. It argued, however, that the advantages could be greater in future if negotiations to provide Alberta gas for United States markets occurred when gas supplies in that country are depleted, rather than now, when there is a perceived over-supply of gas.

6.3 Views of the Board

While it is difficult to accurately forecast future gas supply needs, the Board believes that SoCal's customers represent a large-volume, stable market for Alberta gas. The Board is also persuaded by the evidence provided that the destination of the gas is among the premium markets. The pricing scheme, the high load factor deliveries, a continuing demand charge, and a 60 per cent take or pay clause, are all supportive of that conclusion.

The proposed sale would use existing transportation facilities and the Board understands that any extension of the contract term would defer the scheduled increase in the transportation tariff, allowing Canadian gas to remain competitive in the California market.

The Board notes that the additional volumes contemplated for export are currently in excess of Alberta's requirements. Additionally, there are sufficient supplies of gas available for consumers in Alberta to contract for long-term supplies.

The Board concludes that the issuance of a permit extension would be beneficial to the Alberta public interest.

7 PERMIT TERM AND MAXIMUM DAILY AND ANNUAL VOLUMES

7.1 Views of Pan-Alberta

Pan-Alberta requested that the term of its gas removal permit be extended an additional 15 years beyond 31 October 1997 to 31 October 2012. In effect, Pan-Alberta was seeking a 25-year permit term. The applicant noted that SoCal, which ultimately purchases Pan-Alberta's gas, is obligated by state and federal regulations to seek out secure, long-term gas supplies for core markets (residential, commercial, and small industrial consumers) during the next 12 months or so. Pan-Alberta contended that by extending the permit term now, the Board would define and secure a long-term role for Alberta gas in a lucrative, large-volume market. If the permit term is not extended now, SoCal may need to look elsewhere for long-term supplies, and Pan-Alberta may lose an opportunity that would be unlikely to occur again for a long time. Additionally, Pan-Alberta noted that the contracts relating to the Foothills portion of the pre-build system contain a basket clause that could cause the depreciation rate to increase substantially under certain circumstances.

Pan-Alberta indicated that 92 per cent of producers in Alberta have either signed or made a commitment to sign agreements to extend their contracts to the year 2012, illustrating that producers also recognize the quality of the market and the need to secure a long-term role in it.

Notwithstanding its arguments in favour of extending the term of its permit to the year 2012, Pan-Alberta indicated that, should the Board find that Pan-Alberta's volume of reserves under contract is less than that presented and is inadequate to meet the requirements of the proposed permit, Pan-Alberta would prefer that the amended permit reflect the requested maximum daily and annual volumes (noted in the Introduction), with an extended permit term of less than requested to compensate for the reduced reserves available.

7.2 Views of the Interveners

Vector considered the possibility that the SoCal market could be lost if Pan-Alberta's application were denied as the only factor that could justify the requested term. However, it was sceptical that SoCal would be successful in attempts to contract for alternative supplies for delivery starting in 1997, when Pan-Alberta's existing permit expires. Vector concluded that there were no special circumstances which would warrant an extension of Pan-Alberta's gas removal permit beyond the 15-year period that gas supplies to core markets in Alberta are protected.

WGML supported, in principle, the extension of the term of the permit. It said that if the purchase satisfied the public interest, the Board's commitment to protect gas supplies for core Alberta markets for 15 years ought not to unduly limit contracts which have been freely negotiated by willing buyers and sellers, because such action would restrict the process which deregulation has contemplated would take place.

7.3 Views of the Board

Under the existing statutes, the Board has a responsibility to protect Albertans by ensuring that adequate supplies of natural gas are available for the reasonably foreseeable future. In Decision Report 87-A, the Board confirmed its policy of many years that it would normally grant removal permits to a maximum of 15 years, but would consider terms of up to 25 years in special circumstances. What constitutes special circumstances was to be addressed in future applications.

One factor that could be important in justifying a term longer than normal may be the case where gas removal, while being found to be generally in the Alberta interest, requires significant commitment to infrastructure, either for transportation or for end use. In that circumstance, the Board would consider a term sufficient to allow recovery of the cost of such facilities. This circumstance does not apply in the current Pan-Alberta application.

A consideration of the current application is whether or not the high quality of the intended market would justify a permit term in excess of 15 years. Although the Board accepts that this market will continue to be a premium market for Alberta producers for the foreseeable future, it

is questionable whether a term shorter than 25 years would affect the sale. The Board notes that while the California Public Utilities Commission is encouraging long-term arrangements, it has not specified what time period constitutes the long term. The Board believes that it is reasonable to expect that a 15-year term could well be taken as a long-term commitment in the current environment.

As discussed in Section 6 on the public interest, the Board accepts that the proposed market is likely to be a premium market well into the future. However, although evidence was presented to demonstrate strong preference of the buyer for a term of 25 years, the Board believes a normal 15-year term would continue to reflect a strong commitment of Alberta gas to that market. Moreover, the Board is aware that the market for natural gas in North America is changing as both the quantity and the quality of the surplus change. As this change occurs, there are still many policy questions that have not been resolved. These relate to deregulation, free trade, security of supply, "core markets", and numerous others. Accordingly, the Board is reluctant to depart from its established 15-year permit policy at a time when the market and the policies that affect it are in such an unusual state of transition. In addition, as discussed in Section 4.3 above, the Board has found Pan-Alberta's contracted reserves inadequate to support the proposed 25 years of the permit.

The related question in this application is the potential impact of an increased term on the transportation tariff. The Board understands that any extension to the permit term will defer triggering the depreciation basket clause and thus defer an increase in the tariff. This would happen if the applied-for extension was granted but also if an extension bringing the remaining permit term to the normal 15 years was awarded. Additionally, the Board heard representations that the longer the permit term, the lower would be the depreciation charges on the U.S. side of the border. Although no evidence was provided regarding the quantitative effect this would have on the transportation tariff, the Board does not expect that the difference in the U.S. transportation tariff, on its own, would be significant.

The Board concludes that the southern California market served by SoCal is an attractive and desirable market from the point of view of Alberta's producers of natural gas. The Alberta public interest would be enhanced by maintaining a long-term basis for supplying this market. However, the uncertainties noted above have convinced the Board that, before an unusually long-term commitment is made, a review of several aspects of the process associated with removal permits should be undertaken. The Board intends to fully assess these matters during the next year.

The Board has therefore decided to approve an extension of the existing permit term from 1997 to 2003. This 6-year extension implies a permit term of 15 years from the usual contract renewal date of 1 November 1988 to 1 November 2003.

Should a review of Alberta's policy on removal permits result in favourable consideration of permit terms in excess of 15 years, the Board would be prepared to reconsider and decide on Pan-Alberta's application without reopening the hearing, subject to the appropriate set of conditions then applicable and that no objections are registered at that time.

8 DECISION

Having regard for the evidence presented and conclusions summarized above, the Board is satisfied that the granting of the application, within the limitations imposed by the volume of uncommitted remaining reserves controlled by Pan-Alberta, would be in the public interest of Alberta. The Board is therefore prepared, with the approval of the Lieutenant Governor in Council, to issue an amendment to Permit GR 87-236 which would

- extend the term of the permit by some 6 years to 31 October 2003,
- add an incremental volume of gas permitted for removal of 15.869 x 10^9 m^3, increasing the total volume of gas permitted for removal to 209.169 x 10^9 m^3,
- maintain the annual volume of gas permitted for removal at the existing total of 19.918 x 10^9 m^3 until 31 October 1997, then reduce it to 2.513 x 10^9 m^3 for the remainder of the permit, and
- maintain the daily volume of gas permitted for removal at the existing total of 61.171 x 10^6 m^3 until 31 October 1997, then reduce it to 7.479 x 10^6 m^3 for the remainder of the term of the permit.

The amendment to the permit would be in the form shown in Appendix C and would be subject to the terms and conditions contained therein, as well as any conditions imposed by the Lieutenant Governor in Council.

DATED at Calgary, Alberta, on 26 October 1988.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.

F. J. Mink, P.Eng.

J. P. Prince, Ph.D.

APPENDIX A

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Alberta and Southern Gas Co. Ltd. L. C. Fontaine	
Foothills Pipe Lines (Yukon) Ltd. (Foothills Pipe Lines) J. W. Lutes	
Independent Petroleum Association of Canada D. Sexsmith	
Northwest Alaskan Pipeline Company (Northwest Alaskan) C. R. Rich	
Pacific Interstate Transmission Company (Pacific Interstate) W. M. Smith	
Pan-Alberta Gas Ltd. (Pan-Alberta) F. R. Foran	M. R. Bradshaw G. W. Cameron R. Cech, P.Eng. of Sproule Associates Limited F. E. John of Pacific Interstate W. J. Litvinchuk, P.Eng. R. M. Loch of Southern California Gas Company R. L. Mansell of Wright Mansell Research Limited S. Miller of Southern California Gas Company T. J. Reimer, P.Eng. W. J. Rousch, P.Eng. C. Wadlington of Northwest Alaskan
Petro-Canada Inc. C. B. Woods	
Poco Petroleums Ltd. B. Bender	

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
ProGas Limited N. A. Boutillier	
Southern California Gas Company (SoCal) W. M. Smith	
Vector Energy Inc. (Vector) P. J. McIntyre	J. Kaston, P.Eng.
Western Gas Marketing Limited (WGML) D.I.D. McLean	
Energy Resources Conservation Board staff G. Habib M. E. Mumby L. A. Samson W. J. Schnitzler, P.Eng.	

PAN-ALBERTA GAS LTD. APPLICATION 870705 20 June 1988
REPORT OF RESERVES REVIEW MEETING

This report gives the results of the meeting between Pan-Alberta and ERCB staff to discuss certain of Pan-Alberta's gas reserves supporting its Application 870705 for amendment of its gas removal permit.

REASON FOR THE MEETING

At the hearing of Pan-Alberta's application on 16 and 17 March 1988, it was agreed that differences in estimates of gas reserves should be discussed at a meeting between Pan-Alberta technical staff and ERCB technical staff.

REVIEW PROCEDURE

Because of time constraints, the review was confined to selected pools. A total of 55 pools were proposed for review, with about half of these selected by Pan-Alberta staff and the other half by ERCB staff.

The review meeting was held in the ERCB offices on 12 and 13 April 1988. Each pool was discussed individually, and at the conclusion, Pan-Alberta staff and ERCB staff each declared revisions that they were prepared to make.

Pan-Alberta undertook to provide further information after the meeting for 11 pools and pool groups, which was submitted on 2 May 1988. ERCB staff undertook to do similar further evaluations. After receipt of final information for each pool the meeting chairman made recommendations of reserves values for each pool.

RESULTS OF THE MEETING

a. Mapped Pools

Table 1 summarizes overall results. It shows that the overall difference ratio between ERCB staff and Pan-Alberta improved from 0.71 to 0.79 as a result of the meeting. The chairman's recommendations total 0.83 of Pan-Alberta's estimates.

Table 2 lists, for each pool:

- Pan-Alberta's final reserve values,
- ERCB staff's final reserve values,
- the principal factors of difference, and
- the reserves values recommended by the meeting chairman.

The most common factor of difference was the area of mapped reserves. Pan-Alberta's mapping of proved reserves (by its consultant Sproule Associates Limited) could extend up to approximately one mile from a well (which tested at commercial rates), and mapping of probable reserves could extend another mile beyond that.

ERCB staff mapped only proved reserves in all cases except two. Mapping of these proved reserves could extend up to about 1 and 1/2 mile from a proved well (3 miles between wells).

The chairman's practice in most cases was to recommend the ERCB staff's proved reserves, plus a probable increment of either 25, 50, 75, or 100 per cent of the proved reserves.

Approximately one-half of the final difference between Pan-Alberta and both ERCB staff and the chairman's recommendation occurs in three major pools: Hanlan Beaverhill Lake, Okotoks Crossfield, and Liege Wabiskaw/Grosmont. The factor of difference was material balance and production decline interpretation.

b. Single-Well Area-Assignment Pools

Single-well pools were discussed on an overall basis at the meeting. Pan-Alberta's practice is to assign a proved area of 256 hectares (one section) to most single-well pools, while the ERCB staff's practice in the past in most cases was to assign 200 hectares proved. However, an ERCB staff study of single-well pools in progress for over 2 years has suggested that 200 hectares is overly optimistic for proved reserves for many single-well pools. As a result ERCB staff is in the process of reducing some single-well assignments to 150 hectares. Thus, at the current time, ERCB staff estimates are 0.78 of Pan-Alberta's (256 versus 200 hectares), and in some cases 0.59 of Pan-Alberta's (256 versus 150 hectares).

The meeting chairman favours use of 200 hectares at this time.

APPLICATION OF MEETING RESULTS TO PAN-ALBERTA'S TOTAL RESERVES

a. Mapped Pools

The 54 pools reviewed at this meeting represent less than one-third of Pan-Alberta's total reserves. The reviewed group includes a wide range of different pools and thus could be reasonably representative of all of Pan-Alberta's reserves, with the exception of single-well pools. If the review group results were to be extrapolated to all of Pan-Alberta's mapped pools, a ratio of 0.80 (chairman, post-meeting/Pan-Alberta, pre-meeting) should be applied to totals currently appearing in Pan-Alberta's application. The ratio of 0.83 referred to above would not be applicable because it is based on revisions which Pan-Alberta made as a result of the meeting, and hence do not appear in its original application.

Similarly, if extrapolations were made to ERCB staff totals, a ratio of 1.12 (chairman, post-meeting/ERCB staff, pre-meeting) should be applied to any unreviewed reserves. The ratio of 1.05 appearing in Table 1 would apply only to reviewed reserves.

b. Single-Well Area-Assignment Pools

The situation regarding single-well area-assignment pools is somewhat uncertain at this time because totals for this category were not available and because ERCB staff are in the process of revising some of its 200 hectare assignments to 150 hectares.

The ratio of 0.78 (chairman, 200 hectares/Pan-Alberta, 256 hectares) is relatively close to the 0.80 ratio for mapped pools, and thus it would be reasonable to apply 0.80 to all of Pan-Alberta's reserves.

Equivalent adjustments to ERCB staff totals would involve a ratio of 1.33 (chairman, 200 hectares/ERCB staff, 150 hectares) for 150 hectares assignments, and a ratio of 1.00 for 200 hectare assignments.

Please be aware that the reserves values listed in this report cannot be taken directly as the specific values applicable for gas removal accounting purposes because:

a) The report lists initial reserves values (produced plus remaining) rather than remaining reserves.

b) The report lists the total initial reserves under lands in which Pan-Alberta has an interest, but these have not been reduced to reflect partial interest where this occurs.

c) Values shown for Pan-Alberta are hand calculated estimates of the proportion of pool totals under Pan-Alberta lands. The values to be ultimately used will be generated by computer from the ERCB's provincial reserves files and a computer file of Pan-Alberta's lands-under-contract which Pan-Alberta supplied to ERCB staff on 2 June 1988. This estimate of Pan-Alberta's total remaining reserves will be available shortly.

CHAIRMAN'S RECOMMENDATION

On the basis of the above, the meeting chairman recommends that for gas removal permit considerations:

1. Pan-Alberta's pre-meeting estimate of its total established reserves be adjusted by a factor of 0.80.

2. (a) ERCB staff pre-meeting established reserves estimates for mapped pools be adjusted by a factor of 1.12, and post-meeting revisions be adjusted by a factor of 1.05.

   (b) ERCB staff established estimates for single-well pools be accepted as is for 200 hectare assignments and adjusted by 1.33 for 150 hectare assignments.

3. Changes made on the basis of the above should apply only for purposes of deciding the subject Pan-Alberta gas removal application, and not be integrated as a part of ERCB staff reserves files.

FINAL

The meeting chairman suggests that for future gas removal applications, consideration be given to holding such technical reserves review meetings prior to the hearing of the application.

The chairman thanks the staff and consultants for Pan-Alberta and the ERCB staff for their assistance and cooperation in this review.

H. R. Keushnig

H. R. Keushnig, P.Eng.
Chairman - Reserves Review Meeting

TABLE 1 SUMMARY OF RESULTS (10^6 m^3 of initial established reserves)*

	Pan-Alta	ERCB Staff	Chairman	Difference Ratios: ERCB Staff / Pan-Alta	Difference Ratios: Chairman / Pan-Alta	Difference Ratios: ERCB Chairman / ERCB Staff
Pre-meeting	89 083	63 564	N/A	0.71	N/A	N/A
Post-meeting	85 413	67 585	71 125	0.79	0.83	1.05
Change	-3 670 (-4%)	+4 021 (+6%)				

* Established = Proved + 1/2 Probable.

TABLE 2 PAN-ALBERTA GAS LIMITED
APPLICATION 870705 - AMENDMENT OF GAS REMOVAL PERMIT
REVIEW OF SELECTED RESERVES - 12 APRIL 1988
(10^6 metres^3 initial marketable gas reserves)

PAN-ALBERTA			ERCB STAFF			PRINCIPAL DIFFERENCE FACTORS	RECOMMENDATION	
POOL NAME	PROVED	PROBABLE	POOL DESIGNATION	PROVED	PROBABLE		PROVED	PROBABLE
1. Carrot Creek Rock Creek A Pool 1	563.2	67.8	Carrot Creek Jurassic S,Y, UD	140.0	-	Pool Area	140.0	140.0
2. Carrot Creek Rock Creek A Pool 2	248.8	-	Carrot Creek Jurassic Q,R,X	192.0	-	Pool Area	192.0	192.0
3. Carrot Creek Rock Creek A Pool 3	38.7	-						
4. Carrot Creek Rock Creek B Pool 2	211.4	12.3						
5. Carrot Creek Rock Creek B Pool 1	224.3	94.8	Carrot Creek Rock Jurassic D, UD	142.0	-	Pool Area	142.0	142.0
6. Carrot Creek Rock Creek B Pool 3	136.4	-	Carrot Creek Jurassic T,Z	132.0	-	N/A	132.0	-
7. Carrot Creek Rock Creek B Pool 4	127.0	-	Carrot Creek Jurassic AA	86.0	-	Pool Area	86.0	86.0
8. Okotoks Crossfield	3 249.0	-	Okotoks Wabamun B (North)	3 296.0	-	N/A	3 296.0	-
9. Okotoks Wabamun	3 642.0	-	Okotoks Wabamun B (South)	1 822.0	-	Recovery Factor	1 822.0	-
10. Gladys Crossfield	554.8	312.2	Gladys Wabamun A	304.0	-	Pool Thickness Recovery Factor	304.0	76.0
11. Progress Halfway Pool 1	2 301.0	179.8	Progress Halfway A	2 250.0	-	Pool Area	2 250.0	-
12. Progress Halfway Pool 2	343.4	21.5	Progress Halfway M	257.0	-	Pool Thickness	257.0	60.0
13. Progress Pekisko	113.0	-	Progress Pekisko A	113.0	-	N/A	113.0	-
14. Valhalla Upper Doe Creek	2 423.1	390.2	Valhalla Doe Creek A	3 000.0	-	Material Balance vs Volumetric	3 000.0	-
15. Valhalla Cadotte A	352.7	121.9	Valhalla Cadotte A	102.0	-	Pool Area Pool Thickness	102.0	76.0

PAN-ALBERTA			ERCB STAFF			PRINCIPAL DIFFERENCE FACTORS	RECOMMENDATION	
POOL NAME	PROVED	PROBABLE	POOL DESIGNATION	PROVED	PROBABLE		PROVED	PROBABLE
16. Valhalla Lower Bluesky Pool 1	836.4	-	Valhalla Gething F, G	764.0	-	N/A	800.0	-
17. Valhalla Lower Bluesky Pool 2	46.0	-	Valhalla Gething UD	26.0	-	Pool Area	26.0	13.0
18. Valhalla Halfway Pool 1	480.7	-	Valhalla Halfway B	319.0	-	Porosity	319.0	-
19. Valhalla Halfway Pool 2	725.0	138.6	Valhalla Halfway A	700.0	-	Pool Thickness	700.0	-
20. Wapiti Cadotte Pool 1	117.0	608.3	Not Designated	-	-	Pool Area Lack of Well Tests		
21. Wapiti Cadotte Pool 2	-	30.9	Not Designated	-	-	Pool Area Map	-	15.0
22. Wapiti Cadotte Pool 3	-	8.8	Not Designated	-	-	Pool Area	-	-
23. Wapiti Falher C Pool 1	613.2	-	Wapiti Falher C-3	475.0	-	Pool Area	475.0	119.0
24. Wapiti Falher C Pool 2	1 196.5	-	Wapiti Falher C-1, C-4	993.0	-	Prod'n Performance	993.0	-
25. Wapiti Falher D Pool 2	1 781.9	-	Wapiti Falher D-1	2 690.0	-		2 690.0	-
26. Wapiti Falher D Pool 3	353.2	-						
27. Wapiti Falher E Pool 1	3 255.7	-	Wapiti Falher F-1	2 280.0	-	Material Balance vs Production Decline	2 280.0	1 140.0
28. Sinclair Doe Creek A	25.4	360.1	Knopcik Doe Creek A	20.0	-	Pool Area	20.0	20.0
29. Sinclair Upper Paddy	344.9	234.8	Sinclair Paddy D	367.0	-	Pool Area	367.0	90.0
30. Sinclair Gething A Pool 3	239.2	-	Sinclair Bluesky A, C	109.0	-	Prod'n Performance	109.0	55.0
31. Sinclair Gething A Pool 4	121.8	-	Sinclair Bluesky D, J	250.0	-	Prod'n Decline vs Volumetric	121.8	61.0
32. Sinclair Doig	6 696.1	-	Sinclair Doig A	6 682.0	-	N/A	6 682.0	-

PAN-ALBERTA			ERCB STAFF			PRINCIPAL DIFFERENCE FACTORS	RECOMMENDATION	
POOL NAME	PROVED	PROBABLE	POOL DESIGNATION	PROVED	PROBABLE		PROVED	PROBABLE
33. Steep Creek Belloy	419.1	-	Steep Creek Belloy, UD	345.0	-	Many Factors	382.0	-
34. Steep Creek Falher E	3 018.0	-	Steep Creek Falher E-2	1 310.0	-	Material Balance vs Production Decline	1 310	655.0
35. Hanlan D-2	567.0	-	Hanlan Winterburn B	580.0	-	N/A	580.0	-
36. Hanlan Swan Hills Pool 1	25 187.0	-	Hanlan Beaverhill Lake A, UD	24 000.0	-	Material Balance vs Volumetric	25 000.0	-
37. Hanlan Swan Hills Pool 3	1 426.0	-						
38. Hanlan Swan Hills Pool 2	2 218.7	-	Hanlan Beaverhill Lake B	780.0	-	Material Balance vs Volumetric	780.0	390.0
39. Lambert Leduc	1 365.6	-	Lambert D-3 A	1 250.0	-	N/A	1 250.0	-
40. Minehead Swan Hills	2 613.8	1 706.8	Minehead Beaverhill Lake	2 500.0	-	Pool Area Recovery Factor	2 500.0	600.0
41. Bow Island Sawtooth	616.6	-	Bow Island Sawtooth UD, Burdett Sawtooth UD	339.0	-	Pool Area	339.0	85.0
42. Findley Dunvegan	129.8	260.8	Findley Dunvegan UD	167.0	-	Pool Area	167.0	-
43. Findley Cadomin	25.6	157.9	Findley Cadomin UD	54.0	35	Pool Area	54.0	35.0
44. Findley Nikanassin	96.4	450.5	Findley Nikanassin UD	207.0	62	Pool Area	207.0	62.0
45. Findley Nordegg	183.8	501.5	Findley Jurassic UD	544.0	-	Pool Area	544.0	-
46. Findley Triassic	1 105.0	1 086.0	Findley Triassic A, UD Minnow Triassic UD	474.0	-	Pool Area	474.0	355.0
47. Findley Mississippian	58.8	63.3	Findley Rundle A	145.0	-	Proven vs Probable	145.0	-
48. Fir Leduc Pool 2	1 456.9	-	Fir D-3 A	1 200.0	-	Recovery Factor	1 200.0	-

PAN-ALBERTA			ERCB STAFF			PRINCIPAL DIFFERENCE FACTORS	RECOMMENDATION	
POOL NAME	PROVED	PROBABLE	POOL DESIGNATION	PROVED	PROBABLE		PROVED	PROBABLE
49. Hinton Dunvegan Pool 1	28.5	-	Hinton Dunvegan A	244.0	-	Prod'n Performance	300.0	-
50. Hinton Dunvegan Pool 2	837.0	-						
51. Pine Creek Nordegg A	1 616.0	150.3	Pine Creek Nordegg A	658.0	-	Well Thickness Pool Area Recovery Factor	658.0	164.0
52. Cranberry Debolt	1 360.0	103.9	Cranberry Debolt A	1 512.0	-	N/A	1 512.0	-
53. Liege Wabiskaw & Grosmont	4 548.6	-	Liege Wabiskaw A, Grosmont A	2 171.0	-	Material Balance vs Volumetric	2 171.0	543.0
54. House Grosmont	530.0	-	House Grosmont A	530.0	-	N/A	530.0	-
55. Cessford Medicine Hat	1 011.9	-	Cessford Medicinat Hat A,C,0	1 016.0	-	N/A	1 016.0	-
TOTAL Proven, Probable	81 881.9	7 063.0		67 537.0	97		68 537.8	5 174.0
Established*	85 413.4*			67 585.5*			71 124.8*	
Single-well area-assignment pools	256 hectares	-	Single-well area-assignment pools	200 hectares but many being reduced to 150	-	Pool Area	200 hectares	-

*Established = Proven + 1/2 Probable.

APPENDIX C

Form of Permit*

THE PROVINCE OF ALBERTA

GAS RESOURCES PRESERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a permit to Pan-Alberta Gas Ltd. authorizing the removal of gas from the Province

AMENDMENT OF PERMIT NO. GR 87-236A

(Amending Permit No. GR 87-236)

WHEREAS Pan-Alberta Gas Ltd. has applied to the Energy Resources Conservation Board to amend Permit No. GR 87-236; and

WHEREAS the Lieutenant Governor in Council has given his approval by Order in Council numbered O.C. ________ and dated ____________.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby orders as follows:

1. Permit No. GR 87-236 is amended.

2. Clause 1 is amended by adding the following:

    (k) Application No. 870705 from the Permittee dated 21 May 1987.

3. Clause 2 is amended by striking out "31 October 1997" and by substituting "31 October 2003".

4. Clause 3, subclause (a) is amended by striking out "193 300 000 000" and by substituting "209 169 000 000".

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* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

5. Clause 3, subclause (b) is struck out and the following is substituted:

(b) for the term commencing on the date hereof and ending on 31 October 1997, during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 61 171 000 cubic metres and in a 12-month period such rates shall not exceed 19 918 000 000 cubic metres.

6. The following clause is added after clause 3, subclause (b):

(c) for the term commencing 1 November 1997 and ending 31 October 2003, during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 7 479 000 cubic metres and in a 12-month period such rates shall not exceed 2 513 000 000 cubic metres.

7. Clause 15 is struck out and the following is substituted:

15. (1) Attached hereto as Appendices A and B to this permit is the order of the Lieutenant Governor in Council authorizing the granting of this permit.

(2) This permit is subject to the terms and conditions prescribed by the order of the Lieutenant Governor in Council set out in Appendices A and B.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

LADD EXPLORATION COMPANY
APPLICATION FOR A WELL LICENCE — Decision D 88-18
PROVOST FIELD — Application 881276

1 INTRODUCTION

1.1 Application

Ladd Exploration Company (Ladd) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a licence to drill a well, LADD ET AL PROVOST 16-36-38-2 (16-36 well), in legal subdivision (Lsd) 16 of section 36, township 38, range 2, west of the 4th meridian (section 36).

The purpose of the well is to explore for and recover hydrocarbons from the Dina Member.

1.2 Intervention

The Board received an intervention from Katherine and Thomas P. White (the Whites) opposing the application.

The Whites, who are surface owners of land off-setting the subject lands, argued that the presence of the 16-36 well would have a negative impact on their life-style.

1.3 Hearing

The application was heard on 6 October 1988 at a public hearing held in Provost, Alberta, before an Energy Resources Conservation Board panel comprising E. J. Morin, P.Eng., and Acting Board Members T. F. Homeniuk, P.Eng., and W. G. Remmer, P.Eng.

At the conclusion of Ladd's formal presentation of its application, the hearing participants and the Board visited the proposed well site and the Whites' farmstead.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Ladd Exploration Company (Ladd) W. R. Hawkings, P.Eng.	D. H. Bolen, P.Geol. W. R. Hawkings, P.Eng. A. Bigelow, Land Agent of S.E. Sim & Associates Land Consultants Ltd.
Katherine and Thomas P. White (the Whites) J. W. Bodnar, P.Ag.	Bill and June Luchyk Larry A. Paulgaard Marcella Paulgaard Katherine, Patrick, Richard, and Thomas White
Energy Resources Conservation Board staff G. J. Dodd, P.Geol. V. J. Vogt	

2 ISSUES

The Board considers the issues to be

- need for the well,
- choice of the surface and subsurface location of the well, and
- impacts associated with drilling, completing, testing, and producing the well.

3 CONSIDERATION OF THE APPLICATION

3.1 Views of Ladd

Ladd stated that it has a valid mineral lease and surface agreement for the proposed 16-36 well and, therefore, the right to explore for and recover hydrocarbons from section 36.

Ladd based its choice of well location on several factors, a major one being its interpretation of a seismic line along the northern boundary of section 36 that suggested the presence of a Dina pool in Lsd 16. Ladd added that the proposed well location also lies within the Board-designated target area, Lsd 16, for the oil drilling spacing unit (DSU) comprising the northeast quarter (NE 1/4) of section 36. Ladd stated that to drill outside the target area could cause it, at some point, to be faced with a Board-imposed off-target penalty against oil production from the DSU, and not to drill anywhere within the NE 1/4 of section 36 would eventually result in the loss of its Crown mineral lease for the DSU.

Ladd recognized that, because of the proximity of its proposed well to the Whites' farmstead (approximately 164 metres (m) to the north), there would be an impact on the Whites if the well were drilled. Ladd stated that the proposed well location is some 50 m south of the optimum location on the seismic line at the north boundary of section 36. It contended that a location any farther south, away from the Whites, would move the well farther from the location indicated by its seismic data and would present too great a risk in achieving a successful well.

Ladd also looked at directionally drilling the well but concluded that, at the expected termination depth of 930 m, the well could only be located 100 m to 150 m farther away from the Whites' residence. That limited increase in distance, coupled with the increased cost due to directional drilling, led Ladd to state that it is not prepared to drill the well if the Board would only allow it to be drilled directionally.

Ladd estimated that the total drilling operation would take 12 days. The applicant stated that it knows of no over-pressured zones in the area, including the zone of interest, the Dina Member. Therefore, it does not anticipate any unexpected problems during drilling. Nevertheless, it would employ blowout prevention and associated equipment to prevent an uncontrolled release of hydrocarbons or other fluids to the atmosphere. Ladd added that the possibility of such a release is very remote because its drilling experience in the area confirms that the Dina oil pools do not have an associated gas cap.

Ladd proposed to test the well if it proves successful in encountering hydrocarbons. Ladd stated that the length of the test would depend on the reservoir characteristics, and may need to be as high as 90 days to achieve stable flow in a low-pressure zone. However, Ladd advised that it would have no objection to a test of shorter duration if required by the Board.

Based on its knowledge of the Dina zone in the area, Ladd acknowledged that there is a potential for the release of hydrogen sulphide (H_2S) gas with any production from the well. Using data available from the Provost Dina R Pool, located approximately 4 kilometres (km) to the northwest, Ladd estimated a maximum potential release rate of 0.0004 cubic metres of H_2S gas per second. It further calculated that this necessitated a planning radius of only 10.7 m around the wellhead. Notwithstanding this, Ladd recognized the potential for fugitive H_2S gas odours and would implement measures during testing and producing the well that would minimize the possibility of such odours reaching the Whites' farmstead. These measures would include installing a flare stack to burn the gas produced with the oil during production testing, installing a vapour recovery system on the production tanks and piping the vapour to the flare stack, and having personnel make daily visits to the well site to ensure that the flame on the flare stack remains lit and that well operations are proceeding correctly.

In making its application for a well licence, Ladd assumed that, if the well were successful, its production facilities would be located at the well site and would include equipment consistent with a single-well battery. This would include a flare stack (approximately 6 m high) equipped with a continuous pilot, a bottom-hole screw-type pump with a top drive that would sit on the wellhead (approximately 2 m high), one building to house the motor and hydraulic unit for the well pump and a second building to house the test separator (each building approximately 2.4 m high), and a 120-cubic-metre tank (approximately 6 m high and 6 m in diameter) equipped with vapour recovery piped to the flare stack.

Ladd stated that the production facilities do not have to be located at the well site, but contended that the economics of producing the well should dictate whether or not they could be moved. Ladd stated that, with a poor producing well, the cost of moving the production facilities farther away from the Whites' farmstead might never be recovered. Ladd estimated that moving the production facilities for the 16-36 well could cost $44 000, assuming a 0.6-km-long pipeline costing $30 000, and a lease acquisition and preparation cost of $14 000.

Ladd stated that, should the 16-36 well be successful, there is potential for three additional wells in the NE 1/4, assuming the Board were to approve reduced spacing for the area.

Ladd stated that it would conduct its operations using good oil-field practice and observe all government regulations with regard to safety and environmental protection. In order to minimize the effect of the presence of the 16-36 well on the Whites, Ladd proposed certain additional mitigating measures. These included offering the Whites alternative accommodation during the drilling and completing phases of the well, having its employees and contract workers adhere to a reduced speed limit near the Whites' residence, diking around the lease to prevent any spills from draining to the Whites' property, fencing the lease to prevent unauthorized entry, planting trees and shrubs to screen the well site, retesting the Whites' water well upon completion of drilling operations and comparing the results of water quality and flow rate to results obtained prior to drilling the oil well, and, if the 16-36 well is successful in producing hydrocarbons, oiling the road in front of the Whites' residence to minimize dust.

Ladd stated that it is aware of the Whites' contention that the presence of the well would devalue their property. However, it argued that there is no direct evidence to show that a well next to someone's land decreases the value of the property.

3.2 Views of the Whites

The Whites did not question Ladd's right to the minerals beneath the NE 1/4 nor its right to explore for those minerals. The Whites were concerned, however, that the presence of the well would have a major negative impact on their life-style. They requested that the well licence application be denied.

The Whites stated that they had spoken with the surface owner of the NE 1/4 of section 36 about moving the well location. However, they did not identify an alternative well-site location that would be more acceptable to them, stating instead that they did not want any drilling at all on the land adjacent to their farmstead.

The Whites presented two sets of witnesses and their own children who spoke on their behalf. Bill and June Luchyk and Larry Paulgaard described their experiences with similar oil-field activities in their areas. The Whites' children expressed concern that their parents' life-style would change should the well be drilled. They also expressed concern for the safety of their own children during visits to the farmstead.

The Whites raised specific concerns regarding safety, noise, environmental impact, odours, effects of H_2S gas, visual impact, effects of oil-field drilling operations on their water well, and the possible devaluation of their property due to the proximity of the proposed 16-36 well to their residence.

The Whites stated that their grandchildren often come to visit and they would worry for their safety should they enter the well site. The Whites added that the amount of traffic near their residence would increase, thereby causing a concern for safety and an increase in the noise and dust levels.

The Whites noted that the elevation of the land at their barns and corrals is lower than at the well site. This causes them concern that any fugitive H_2S gas would accumulate in that area, and that any spills at the well site would drain towards their land. The Whites also worried that drilling and operating the proposed well could contaminate their water well or disrupt its flow.

The Whites observed that the proposed well and any production facilities would be directly opposite their living-room picture window. They noted that Ladd had offered to plant trees at the well site to screen the facilities but argued that such trees would take many years to reach a height sufficient to be effective. The Whites stated that moving the production facilities from the well site would relieve some of their concerns but offered no suggestion as to where those facilities might be located.

The Whites stated that, of the many concerns they have, their major concern is an apprehension or fear that there might be a release of H_2S gas from the well. The Whites presented a letter from their family doctor stating that a family member has a history of anxiety-related health problems. They expressed concern that, if the proposed well were drilled, the worry would continue and the health condition would deteriorate further.

The Whites were also concerned that, should the 16-36 well be successful, it would lead to drilling more wells on the land adjacent to their farmstead.

3.3 Views of the Board

The Board accepts that Ladd has the necessary mineral lease and that a well is needed to allow it to explore for and recover hydrocarbons from the DSU. The Board also accepts that Ladd has reached an agreement with the surface owner for a surface lease. However, existence of a valid mineral lease and a surface lease agreement is not in itself sufficient to justify approval of Ladd's well licence application. The Board must also consider the concerns of other parties who may be affected by drilling the well.

Mineral lease owners have certain constraints or restrictions with which they must comply when exploring for and recovering hydrocarbons. The Board believes it would be useful to describe these to help understand the selection of the proposed well location. The attached figure is added to assist in this understanding.

Mineral leases are divided into drilling spacing units, with oil DSUs normally comprising an area of one quarter section. In this case, the DSU consists of the NE 1/4 of section 36. Should Ladd's proposed well encounter oil in the Dina Member as anticipated, the well would have to be completed within the NE 1/4 of section 36 to allow it to be produced. In addition, each DSU is assigned a target area. In the case of the NE 1/4 of section 36, the target area is Lsd 16. The designation of a target area is necessary to distribute wells throughout a pool and ensure equitable production among several mineral lease owners. If there are several mineral lease owners with wells in adjacent DSUs that are completed in the same pool, then production from those wells not completed in their target areas would be subject to an off-target penalty, ie, a severe restriction to production. One of the reasons Ladd has located its proposed well within the target area is to avoid a possible future off-target penalty.

Notwithstanding these conditions, a mineral lease owner such as Ladd can apply to the Board for a change in spacing or target area. In this case, there is no purpose in Ladd applying for such a change as the existing DSU and its target area coincide with the optimum exploratory location indicated by seismic. If that location is productive, then Ladd may apply for reduced DSUs to permit the drilling of perhaps three more wells, as indicated in its evidence.

The Board notes that Ladd selected its proposed well location to coincide with an anomaly identified from an east-west seismic line along the north boundary of section 36. While this seismic data defines the anomaly in terms of east-west direction and depth, it does not define it in the north-south direction. The Board believes that an additional seismic line in the north-south direction would provide that information and, hence, indicate whether or not the well could be moved south to increase the distance between the well and the Whites' farmstead. However, the Board also recognizes and accepts Ladd's argument that its proposed well should be completed in the Lsd 16 target area to avoid any future off-target penalty. This means that, even if a north-south seismic survey were to indicate that the anomaly extended some distance

to the south, the well location could only be moved a maximum of 350 m and still remain on target. Given the nature of the Whites' concerns, the Board does not believe that a move of 350 m south would significantly alleviate these concerns. The Board notes that the Whites did not want any drilling at all on the land adjacent to their farmstead. For similar reasons, the Board does not believe that the increased risk and cost associated with directional drilling can be justified to achieve a minor move of the well location in the order of 100 m to 150 m to the south.

Given the seismic data presented by Ladd and the constraint imposed by the target area for this DSU, the Board believes that there is very limited flexibility in locating the proposed well. Whether or not the proposed well should be allowed would depend on the impacts it might have on the Whites. This matter is dealt with in the following paragraphs. To assist it in dealing with the concerns identified by the Whites, the Board considered the concerns in terms of the different phases of drilling, testing, and producing the well.

The Board accepts Ladd's estimate that the well can be drilled in 12 days. Based on its knowledge of the Dina zone in the area, the Board is of the view that the potential for a blowout during drilling is extremely remote. The Board also believes that, in the unlikely event of a blowout, the H_2S gas levels would be too low to create a safety hazard for the Whites. During the drilling phase, there will be some increase in local traffic, some increase in noise levels from the drilling rig and from the traffic, and the visual impact of the drilling rig itself. However, the Board believes these impacts to be largely of a nuisance variety and of a relatively short duration. These are not unlike impacts occurring all over the province and certainly not of sufficient consequence to prevent drilling the well.

During the testing phase, nuisance-type impacts, similar to those during the drilling phase, would occur. In addition, because the well would be produced during the testing phase, there would be the visual impact associated with storage tanks, flare stack, wellhead, and pumphouse. Although there may be odours from any vapour that is not collected and flared, these would be minimized with proper equipment and operation. Assuming the well is drilled and the testing phase becomes necessary, the Board would limit the testing period to 30 days in order to minimize the length of time over which the associated nuisance impacts could prevail.

During the production phase, the on-site equipment proposed by Ladd would be a wellhead, screw-type pump and enclosure, separator and enclosure, storage tank, and flare stack. In addition, the site would be visited daily by an operator driving a pickup truck and 2 to 3 times weekly by a tank truck that would haul the produced oil from the storage tank. Since production operations would exist for many years, the Board believes that the proposed well-site facilities and the proximity of the site to the Whites' farmstead would result in an unacceptable visual impact to the Whites unless some mitigative measures are taken.

Specifically, the Board would expect Ladd to utilize low-profile equipment and, if necessary, tree screening along the north boundary of section 36 immediately across from the Whites' residence. The Board notes that partial screening will be provided by the trees and shrubs at the Whites' farmstead and native trees along the north boundary of section 36. The Board does not believe that existence of the well would result in a significant increase in traffic nor would there be a significant increase in related noise and dust.

The Board has considered the H_2S gas levels associated with oil production from the Dina zone and agrees with Ladd that these levels are too low to present a safety hazard. However, the Board believes that the levels are sufficiently high to result in a potential odour problem. Nothwithstanding Ladd's intention to collect and flare gas production and tank vapours, the Board is of the view that fugitive odours may result from truck loading and normal production operations. In this case, the Board believes that the proximity of the well to the Whites' farmstead may result in unacceptable odour levels at the farmstead. Given the description of the production facilities provided by Ladd, the Board would not allow such facilities to be installed at the 16-36 location. It is the Board's view that production facilities for a well drilled at the 16-36 location would best be located remote from the site to avoid odour problems at the Whites' residence. Nevertheless, production facilities might be allowed on the 16-36 location if special measures are taken in their design and operation.

With respect to the Whites' concerns that their water well may become contaminated and that drainage from the well site would cross their land, the Board believes these matters are unlikely and in any case can be mitigated. The Board would expect Ladd to conduct water well tests to determine whether or not the quantity and quality of water had been affected and to take any corrective action that might be necessary. The Board would also expect Ladd to construct appropriate dikes or berms to contain any spills or leakage to the well-site area.

4 CONCLUSION

The Board concludes that there would not be any major impacts associated with drilling the proposed well. The impacts that would occur would be of a minor, nuisance nature and, in any event, would persist for the short period during which the well would be drilled. The Board concludes that the proposed well can be drilled.

The Board similarly believes that the well, if successful, can be tested. The Board would approve a testing period of only 30 days to limit the period during which nuisance impacts may occur. In addition, the Board expects Ladd to implement the mitigating measures that it described in its application and at the hearing to minimize any impacts on the Whites during drilling and testing of the well.

The Board also concludes that, because of the proximity of the proposed well site to the Whites' farmstead, it is possible over a long period of time that the Whites would be subjected to H_2S gas odours when the well

is produced and oil transported from the site. Therefore, the Board advises Ladd that approval would not be given for permanent production facilities, as described at the hearing, at the 16-36 well site.

The Board notes that Ladd is required to submit an application to the Board for production testing the 16-36 well, and later an application for approval of permanent production facilities. At that time, the Board will have regard for the commitments made by Ladd and the adequacy of the design and operation of the facilities.

The Board also notes that, if the 16-36 well is successful, Ladd may apply for reduced spacing and may drill additional wells. If additional production results, the Board would expect Ladd to consolidate its production facilities on section 36 as far away as possible from the Whites' residence.

5 DECISION

The Board grants Application 881276 and will issue a well licence to permit the drilling of the well, LADD ET AL PROVOST 16-36-38-2.

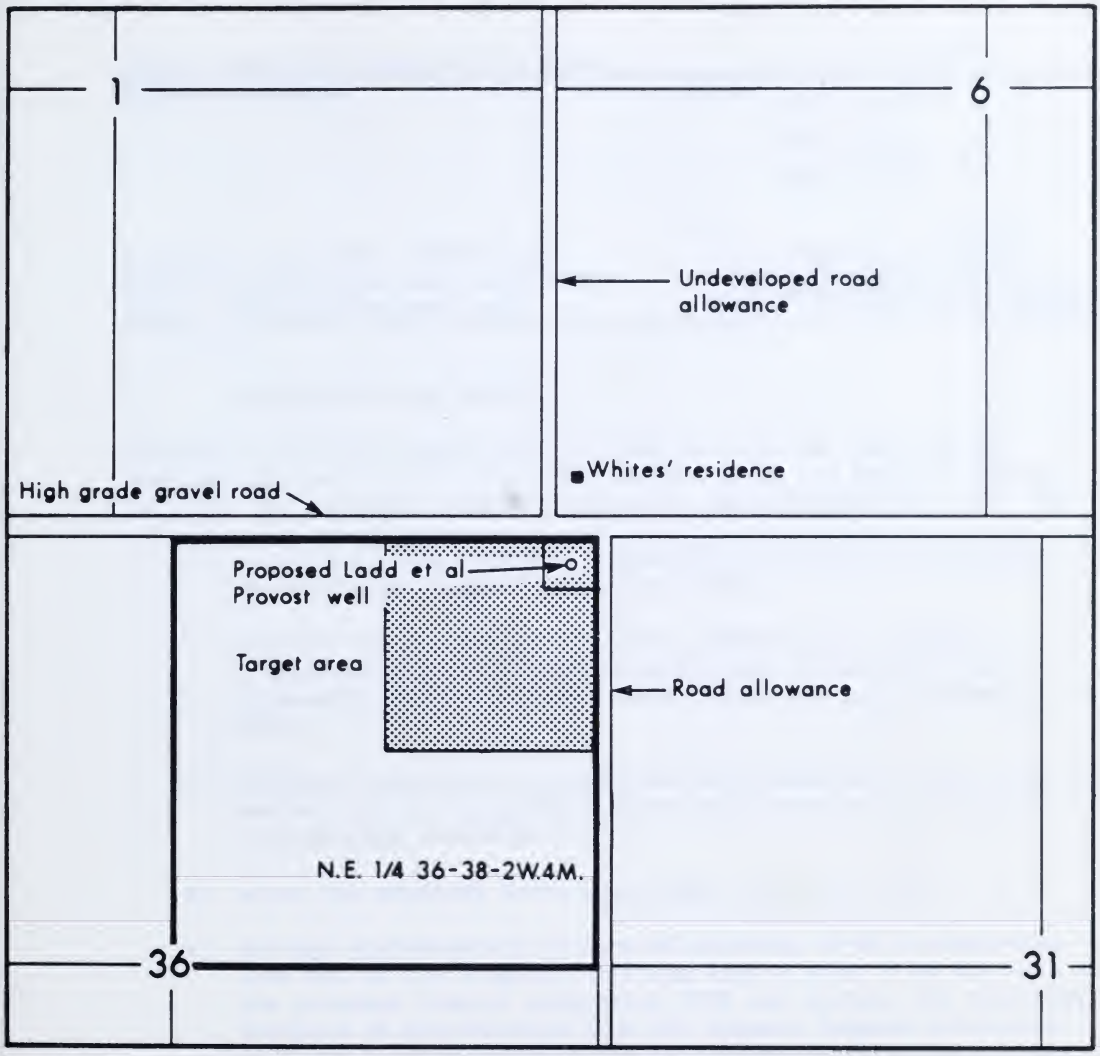
DATED at Calgary, Alberta, on 25 November 1988.

ENERGY RESOURCES CONSERVATION BOARD

E. J. Morin, P.Eng.
Board Member

T. F. Homeniuk, P.Eng.
Acting Board Member

W. G. Remmer, P.Eng.
Acting Board Member



LADD ET AL PROVOST 16-36-38-2(W4) PROPOSED WELL
Application No. 881276

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

TRANSALTA UTILITIES CORPORATION
138-kV TRANSMISSION LINE FACILITIES
NORTH LETHBRIDGE-TEMPEST AREA

Decision D 88-19
Application 880963

1 APPLICATION AND HEARING

TransAlta Utilities Corporation (TransAlta) applied, pursuant to sections 12, 14, 16, 17, 18, and 20 of the Hydro and Electric Energy Act, for the necessary permits, licences, and approvals to

a) construct a new 138/69-kV substation in the NE 22-8-19-W4M designated as Tempest substation 403S;

b) construct approximately 37 km of 138-kV single-circuit transmission line from North Lethbridge substation 370S to proposed Tempest substation 403S designated as transmission line 820L;

c) salvage a portion of existing 138-kV transmission line 172L and reconstruct it on double-circuit poles with proposed 138-kV transmission line 820L;

d) alter the existing North Lethbridge substation 370S;

e) salvage approximately 10.5 km of existing 69-kV transmission line 66L on the diagonal starting from a point 8 km due east of the proposed Tempest substation 403S and operate the remaining portions of transmission line 66L between Tempest substation 403S and Taber substation 83S as a 25-kV distribution circuit;

f) alter the existing Taber substation 83S; and

g) interconnect the aforementioned facilities with the applicant's transmission system and operate them.

The existing and proposed systems in the area are shown schematically in figure 1. TransAlta proposed two possible routes as shown on the figure, stating a preference for TransAlta Alternative No. 1.

The application was considered at a public hearing on 31 August 1988, in Lethbridge, Alberta, with G. J. DeSorcy, P.Eng., J. P. Prince, Ph.D., and E. R. Brushett, P.Eng., sitting. After the close of the hearing,

the Board was advised by Mr. Z. Gergely that he had not received notice of the hearing. The Board decided to re-open the hearing to hear evidence respecting Mr. Z. Gergely's concerns. In addition, TransAlta subsequently amended its application with respect to the route along the Duban and Glover property, sections 23 and 24, township 9, range 21, west of the 4th meridian. Mr. Duban and the Glovers were advised that the amendment would be considered at the re-opening of the hearing.

TransAlta also advised Mr. J. Gergely that at the re-opened hearing they would discuss certain transmission line options that may affect his property, located in the northwest quarter of section 33, township 8, range 20, west of the 4th meridian, and therefore invited him to attend. Accordingly, the hearing was re-opened on 24 November 1988, at the Board's office in Calgary, with G. J. DeSorcy and J. P. Prince sitting as a quorum.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
31 August 1988	
TransAlta Utilities Corporation (TransAlta) J. G. Friesen	S. E. Hodgkinson, P.Eng. N. J. Brausen, P.Eng. J. S. Rohrich, R.E.T. W. H. Bailey, Ph.D.
N. van Ryn	N. van Ryn
D. Duban	D. Duban
K. and E. Glover (the Glovers) K. Glover	K. Glover
Melcor Developments Ltd. (Melcor) W. Stewart	W. Stewart
The Crown in Right of Alberta R. Dyer	
Energy Resources Conservation Board staff C.J.C. Page T. Chan, P.Eng. P. Forbes	
24 November 1988	
TransAlta Utilities Corporation (TransAlta) J. G. Friesen	S. E. Hodgkinson, P.Eng. J. S. Rohrich, R.E.T.

THOSE WHO APPEARED AT THE HEARING (continued)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Z. Gergely	Z. Gergely
J. Gergely	J. Gergely
D. Duban	D. Duban
Energy Resources Conservation Board staff C.J.C. Page P. Forbes	

At the hearing, the interveners did not question the need for the proposed facilities. However, they did state concerns regarding the location of the line relative to their respective properties. Mrs. van Ryn also raised concerns regarding possible health effects caused by the proposed transmission line.

2 PRELIMINARY MATTERS

TransAlta stated at the commencement of the November hearing that although it had no objection to the re-opening with respect to the amendment of its application along sections 23 and 24, township 9, range 21, west of the 4th meridian, the hearing should not be re-opened for Mr. Z. Gergely who was not an intervener at the initial hearing. The reasons TransAlta felt the hearing should not be re-opened for Mr. Z. Gergely were:

a) The Notice of Hearing was sent to the Bank of Montreal which was the registered owner of the property and it was beyond TransAlta's control if the bank did not notify the occupant.

b) The hearing was advertised.

c) Mr. Gergely had notice of the proposal prior to the open house which was held by TransAlta.

TransAlta indicated that it was not asking for a ruling at the time of the hearing, but that the matter be taken into account after considering the evidence, and that the Board indicate in its decision whether or not the hearing should be re-opened for Mr. Z. Gergely.

During questioning TransAlta stated that although it believed that Mr. Z. Gergely was aware of the TransAlta proposal, it had no knowledge that he was aware of the hearing date or the date for filing of submissions.

Mr. Z. Gergely stated that he was not notified of the hearing and did not find out about it until it was over.

Board counsel indicated that, pursuant to section 29 of the Energy Resources Conservation Act, notice must be given to any person directly and adversely affected by an application and an occupant of lands, as well as an owner, may be a person affected. Further, section 43 of the Act provides that if an affected party does not receive direct notice of a hearing, and if that party applies to the Board, a hearing must be held.

TransAlta submitted that section 43 did not apply until after an order had been issued.

The Board accepts that Mr. Z. Gergely may have been generally aware of the TransAlta proposal but finds nothing in the evidence to indicate he was aware of the August hearing. The Board believes that Mr. Z. Gergely, as an occupant of the land in question, was a party affected by the application and entitled to receive notice.

The Board notes TransAlta's argument that section 43 does not apply until after an order or direction has been issued, but believes the spirit and intent of section 43 is to allow parties who inadvertently did not receive notice the same right to be heard as those who did. To delay the re-opening of the hearing until after an order was issued, to then suspend the order, hold another hearing, and issue a second decision report would only add undue time and expense to the process.

The Board further notes that if section 43 were to be construed in a literal fashion, so as to preclude Mr. Z. Gergely from appearing before the Board before an order was issued, the Board, pursuant to section 42 of the Energy Resources Conservation Act, may re-hear an application before deciding it.

Therefore, the Board believes it was proper to hear Mr. Z. Gergely at the re-opened hearing and to consider his concerns in reaching a decision.

3 ISSUES

The Board believes the issues are

- o the need for the proposed transmission system changes, and
- o the location of the proposed transmission line.

4 NEED FOR THE PROPOSED TRANSMISSION SYSTEM CHANGES

4.1 Views of the Applicant

The applicant stated that in the Stirling and Warner areas a significant portion of the electric load is for irrigation pumping. Hence, the area load peaks in summer. The peak load is forecast to be 15.5 MW by 1990. The applicant submitted that the existing 69-kV transmission system in

the area, which is sourced at Taber and Magrath, is not capable of supplying the peak load during abnormal system conditions. By means of loadflow diagrams, the applicant demonstrated that during the 1989 summer peak, certain transmission line outages could result in unacceptably low voltages in the Stirling and Warner areas. To overcome the low-voltage situation, the applicant proposed to build

a) a new Tempest substation 403S located approximately 18 km north of Stirling substation 67S and adjacent to the existing 69-kV line 66L, and

b) a new 138-kV transmission line from North Lethbridge substation 370S to Tempest substation. Stirling substation would then be supplied from Tempest substation via the existing 69-kV line 66L. The diagonal portion of 66L between Tempest substation and Taber substation would be salvaged after the new 138-kV line is built. The remaining portion of 66L would be converted to operate as a 25-kV distribution circuit.

4.2 Views of the Interveners

The interveners did not comment on the need for changes to the proposed facilities.

4.3 Views of the Board

The Board is satisfied that the electric load in the Stirling-Warner area can be expected to grow generally as predicted by TransAlta. Having reviewed TransAlta's loadflow studies, it agrees that the present 69-kV transmission system needs upgrading to avoid low-voltage conditions resulting from equipment outages.

The Board has considered the method that TransAlta proposed to improve the transmission system in the area. It believes that a new 138/69-kV substation at Tempest and a new 138-kV line from North Lethbridge to Tempest could eliminate undervoltage in the event of any of the single contingency outages that the applicant enumerated. However, since the Warner substation would remain on a radial feed after the proposed facilities were built, about 45 per cent of the load supplied by Warner substation would still be vulnerable to outages of the radial feed from Stirling. Therefore, while confirming a need for the proposed facilities, the Board would ask TransAlta to monitor closely the load growth in the Warner area and, as soon as circumstances warrant, develop a second feed to Warner.

5 LOCATION OF THE PROPOSED TRANSMISSION LINE

5.1 Views of the Interveners

Mr. Duban, the lessee of lands in the northwest and northeast half, section 23, township 9, range 21, west of the 4th meridian, expressed

concern about the transmission line possibly interfering with his pivot irrigation system. The lands in question and the proposed location of the line are shown on figure 1. Mr. Duban indicated that a 25-kV distribution line located on the west side of the property now interferes with his irrigation system. He wished to ensure that the proposed line did not exacerbate the problem.

At the August hearing, Mr. Duban commented on TransAlta's proposed amendment to locate the line approximately 6 m (20 ft) north of the south road allowance boundary adjacent to his property. He indicated his main concern was that if the proposed structures of the line were not staggered properly, they would not allow the pivot system to complete its turn. He would then have to shorten it. He also stated that the line, if constructed in this location, would be very close to the path of water flow from the irrigation system. The water flow would, at times, hit the line. Mr. Duban also expressed concern that TransAlta's amendment might not be able to proceed, since it would be subject to the approval of the County and St. Mary's Irrigation District. Subsequent to the August hearing, TransAlta advised that it was unable to obtain these approvals and again amended its application back to its original proposal, to place the line 1 m from the road allowance boundary. At the November hearing, Mr. Duban agreed to the location of the line providing the pole settings did not interfere with the half section pivot irrigation system and allowed for Mr. Glover's future plans to install quarter section pivot systems.

Mr. Glover leases his property to Mr. Duban. He, too, was concerned that the proposed line would interfere with Mr. Duban's irrigation system. He also expressed concerns respecting the line's proximity to the Sunny Side School, and the possibility of soil erosion along his property.

Mr. Glover stated that he would prefer to see the line located on road allowance along the north side of the road opposite his property, and noted that TransAlta initially, in its preliminary disclosures, had planned to construct the proposed line on the north side of the road. He contended that tree clearing on the north side would not be substantially greater than that required along the proposed route.

Mr. Glover indicated at the hearing that his concerns would be alleviated if TransAlta designed and located the line so as not to interfere with the pivot irrigation system.

Melcor did not object to the need for or the location of the transmission line, but was concerned about the detrimental impact of the proposed structures on the value and potential use of its land, located in the southwest, southeast, and northeast quarters of section 18, township 9, range 21, west of the 4th meridian, as shown on figure 1.

Melcor questioned TransAlta regarding the possibility of locating the proposed line on the existing 240-kV towers which are presently located

north of the Lethbridge substation, or of using special metal poles which would have less aesthetic impact.

Mrs. van Ryn is the owner of lands located in the northwest quarter, section 16, township 9, range 20, west of the 4th meridian, as shown on figure 1. She was concerned that the location of the line, approximately 25 m from her residence, would be a health hazard to her because of electric and magnetic fields from the line. She had read research findings linking transmission lines with childhood leukemia. Although the results were not conclusive, she would not feel comfortable living close to a 138-kV line since she believes that the fields of the line would suppress the human immune system. She stated that she would consider moving away if Alternative 1 were approved. However, she also stated that she could not afford to do so, and thus suggested other possible alternative routes for the proposed line.

Mrs. van Ryn proposed two alternative routes, one being 1 mile (1.6 km) west of TransAlta's preferred route and the other one-half mile (0.8 km) to the east of the preferred route along a quarter section line. She submitted that the cost and other impacts of her west alternative were not significant when compared with TransAlta's Alternative 2. Mrs. van Ryn stated that her west alternative had five fewer residences than TransAlta's preferred route based on residents located 50 m away from the proposed line, rather than the applicant's proposed separation distance criterion of 100 m.

She stated that an irrigation ditch and right of way existed along the northern part of her east alternative for one-half mile (0.8 km). This would provide easy access and no interference with sprinkler systems. Mrs. van Ryn initially indicated that she believed she could obtain agreement from all landowners along her eastern alternative. Subsequently, she contacted all the parties affected but was unable to obtain a complete set of consents.

Mr. Z. Gergely is the owner of the land in the northeast quarter of section 32, township 8, range 20, west of the 4th meridian, as shown on figure 1. He expressed concern about possible interference by the transmission line with his future plans to construct a helicopter pad and establish a helicopter training school. He indicated that the height of the transmission line would be very dangerous and would interfere with the approach alignment for the helicopter pad, particularly when the possibility of student pilot errors is considered.

In response to TransAlta's proposal to lower the structure profile to accommodate a proper glide path for the helicopter approach, Mr. Z. Gergely stated that the line would still be hazardous to student pilots since they would have to fly parallel to and over the line. Mr. Z. Gergely indicated that there were no alternatives for the location of the helicopter pad on his property.

Subsequent to the hearing, Board staff, TransAlta, and inspectors from Transport Canada visited the Gergely helicopter pad to establish distance measurements from the proposed helicopter pad apron to the existing distribution power line, the proposed 138-kV transmission line, and to other obstacles in the area. The heights above ground of the distribution line and the various obstacles were also measured.

Figure 2 shows the locations of the Gergely land and proposed helicopter pad, and a cross-section of a possible east-west flight pattern to the pad.

Mr. J. Gergely, owner of the land in the northwest quarter of section 33, township 8, range 20, west of the 4th meridian, was concerned mainly with the visual impact of the transmission line, which would interfere with his view of the mountains. He also expressed concerns that if TransAlta required a 6-m easement on his property for two-pole structures in order to lower structure heights to accommodate Mr. Z. Gergely's concerns, the poles would interfere with his irrigation system. However, Mr. J. Gergely did not comment on interference from single-pole structures with his irrigation pivot system. Mr. J. Gergely also expressed concerns regarding water contacting the conductors and thereby increasing the risk of electrocution.

5.2 Views of the Applicant

TransAlta proposed two alternative routes, but stated a preference for Alternative 1 since it involved eight fewer residences within 100 m and a lower cost.

The alternative routes are shown on figure 1. Alternative 1 was estimated to cost $2 634 000, approximately $336 000 less than Alternative 2. Although the applicant had a preference for Alternative 1, it stated that it is prepared to build on either route.

In response to Mr. Duban's and Mr. Glover's irrigation concerns, TransAlta indicated that the road allowance adjacent to sections 23 and 24, township 9, range 21, west of the 4th meridian, was widened by approximately 5 m (17 ft) on the south side several years ago. Because of possible pivot irrigation system conflicts with Mr. Duban's system, the applicant proposed an amendment to the application at the August hearing. It proposed locating the new line approximately 6 m (20 ft) north of the south boundary of the road allowance crossing sections 23 and 24. The applicant stated that this amendment would totally avoid any physical conflict with the pivot irrigation system that operates in section 23.

Subsequent to the hearing on 31 August 1988, TransAlta was unable to obtain approval for its amendment from the County and St. Mary's Irrigation District, and further amended the application back to the original proposed alignment. It did state, however, that it could

increase the span length and design the line so as not to interfere with Mr. Duban's half section pivot system and Mr. Glover's future plans for quarter section pivot systems.

Regarding erosion along the proposed route, TransAlta contended that it did not expect any erosion problems alongside the Glovers' property. It stated that there has been a distribution line in this location for several years, and that it routinely builds similar lines along road allowances and could design this line to avoid erosion problems.

In response to the concerns of Melcor, TransAlta commented that the wood-pole structures in the vicinity of Melcor lands are the standard structures used throughout its service area. It stated that the proposed structures are similar to those that have existed on the right of way adjacent to the Melcor property for a number of years, and noted that it was simply proposing to remove the existing wood-pole line and rebuild a very similar wood-pole line in its place in the same location. In response to Melcor's comment about hanging the proposed conductors on the existing 240-kV steel towers, TransAlta stated that the towers are not designed to accommodate more lines.

TransAlta evaluated the two alternative routes proposed by Mrs. van Ryn and contended that the van Ryn east proposal would cost approximately $37 000 more than the applied-for preferred route. In addition, there would be extra right of way cost, estimated to be $20 000, as the line would be on private lands rather than road allowance. The van Ryn west route was estimated to cost approximately $45 000 more than the applied-for preferred route because of extra tree clearing and AGT cables along that road allowance.

In response to Mrs. van Ryn's health concerns, TransAlta calculated the electric and magnetic fields that would be expected within the vicinity of the proposed line and near her home, which is approximately 25 m from the line. The applicant submitted that the electric field strength directly beneath the conductor of the proposed line would be approximately 1.1 kV per metre. The field strength would decrease with distance from the line and would be about 0.15 kV per metre in the vicinity of Mrs. van Ryn's home. Shielding effects provided by trees and the walls of the house would reduce the electric field strength of the proposed line to a negligible level within the home.

With respect to the magnetic field attributable to the proposed line, TransAlta estimated that the maximum magnetic flux density beneath the line would be about 4.9 milligauss. Similar to the electric field strength, the magnetic flux density also decreases with distance from the line. It would be about 0.5 milligauss at Mrs. van Ryn's home. TransAlta stated that the magnetic fields due to household wiring and common appliances could be ten times or more higher than the 0.5 milligauss caused by the line. Therefore, it submitted that the magnetic field due to the proposed line would be typical of the level that one is normally exposed to daily. Dr. Bailey also pointed out that

the earth's natural magnetic field has an intensity much higher than 0.5 milligauss. It ranges from 500 to 600 milligauss depending on geographical locations.

Dr. Bailey stated that in the past 20 years, scientists have conducted a wide variety of studies to investigate the health effects of electric and magnetic fields. Since the mid-1970s, panels of independent scientists in the United States and abroad have evaluated the study results to determine the possibility of health risks. These panels did not identify adverse effects due to electric and magnetic fields generated by transmission lines. Specifically, the World Health Organization in its 1987 report concluded that magnetic fields of 10 000 to 50 000 milligauss have not been shown to produce any significant biological effects.

With respect to questions raised in the media regarding associations between cancer rates and magnetic fields, Dr. Bailey indicated that such associations were only suggested by two epidemiological studies in Denver, Colorado. However, he commented that epidemiological studies are purely observational and that the associations as reported are very weak. According to Dr. Bailey, the results are inconsistent and not supported by biological researchers. The assessment of field exposures used in the studies was also indirect and imprecise.

Dr. Bailey indicated that the New York State Public Service Commission had reviewed the epidemiology research done in Denver by Dr. Savitz, who suggested the possible links between magnetic fields and cancer in children. It concluded that the research revealed no evidence that magnetic fields pose a health hazard.

Hence, Dr. Bailey submitted that there is no scientific basis to support Mrs. van Ryn's concerns that electric and magnetic fields due to the proposed line would be harmful to her.

In response to Mr. Z. Gergely's concerns regarding glide path interference with his proposed helicopter pad, TransAlta provided, at the November hearing, optional structure configurations for the line, as shown in figure 3. TransAlta was confident that it could lower the structure profile and design the transmission line along the east side of the road so that it would meet Transport Canada's 8 per cent glide path regulation for the heliport approach pattern. TransAlta observed that the location of the proposed pad and proposed glide path is presently constrained by other features, such as the existing rural line that runs north-south along the west side of the road allowance just to the east of Mr. Gergely's property.

TransAlta's option 1 lowers the structure profile to approximately 13 m (43 ft) using a single-pole structure. Option 2 lowers the structure profile to approximately 10 m (32 ft) using two-pole structures. The two-pole structures for option 2 would require a 6-m

easement on J. Gergely's property for access during construction and maintenance of the line.

In response to J. Gergely's concerns that the two-pole structures and a 6-m easement would interfere with his quarter section pivot irrigation system, TransAlta stated that it would be prepared to design the line so that it would not interfere with the pivot system. Option 2 would consist of two two-pole structures, each with one pole on private land. They would be approximately 2 m (7 ft) from the property line. TransAlta stated that the structures would be located towards the northwest corner of Mr. J. Gergely's section and be roughly in line with an east-west flight path from the proposed helicopter pad. TransAlta said that it would install a longer span at that location so that a pivot irrigation system would operate without interference.

In response to Mr. J. Gergely's concerns about water from his irrigation sprinkler system contacting the line, TransAlta stated that the only concern is if a solid stream of water contacts the conductors and that it could design these lines to prevent this from happening.

5.3 Views of the Board

The Board notes that the applicant has proposed two alternative routes, preferring Alternative 1 since it involves fewer residences and lesser cost. Alternative 1 is estimated to cost approximately $336 000 less than Alternative 2 because of less tree clearing and avoidance of both the costs of overbuilding some of the existing distribution circuits and of relocating existing distribution lines throughout the area. The Board therefore considers that the applicant's preferred route, Alternative 1, has a significant advantage, in terms of cost, over Alternative 2. The Board sees no difference between the two alternatives in terms of the technical ability to overcome the present shortcomings of the system.

In terms of impact of the proposed line on the public, the Board notes that no one appeared to oppose Alternative 2, although several raised concerns regarding Alternative 1. The Board has carefully considered the concerns raised by the interveners respecting Alternative 1, to determine if the impacts are significant enough to justify the higher costs associated with Alternative 2.

The Board has examined the concerns presented by Mr. Duban and Mr. Glover respecting the ability to operate a pivot irrigation system with the proposed route and line in place. It notes TransAlta's agreement to design and build the line so as not to interfere with existing and future pivot systems. The Board also notes the acceptance, by Mr. Glover and Mr. Duban, of the physical aspects of the proposed line if it is built as agreed to by TransAlta, even though they have concerns respecting financial aspects.

The Board therefore concludes that an alignment adjacent to the Duban and Glover property, on its original proposed alignment 1 m from the

property line, would be appropriate, subject to its construction as agreed to by TransAlta at the hearing. Additionally, the Board does not believe that a transmission line along this alignment would cause soil erosion or interfere with the Sunny Side School, since the latter is approximately 120 m from the proposed line.

Regarding Melcor's concerns, since the proposed line would replace a similar line existing on the same right of way, the Board does not believe that the proposed line would have a significant adverse effect on the value and potential use of Melcor's land. The Board notes Melcor's suggestion of tubular steel poles rather than wooden structures along Melcor's land to make the line more attractive. However, tubular steel poles would approximately double the cost of wood structures. The Board does not believe this additional expenditure is justified and therefore concludes that the proposed route alignment and structures are suitable in the vicinity of the Melcor lands.

The Board recognizes and appreciates the concerns of Mrs. van Ryn regarding possible health effects associated with electric and magnetic fields. Having carefully reviewed the evidence submitted at the hearing with respect to the issue, it accepts that the calculated strengths of the electric and magnetic fields in the vicinity of the proposed line are small and that they decrease with distance from the line. The shielding effects provided by trees and the walls of Mrs. van Ryn's house would further reduce the strength of the electric field of the proposed line.

The electric and magnetic fields due to the proposed line at Mrs. van Ryn's house would be very small compared with fields due to household wiring or those of the earth. Additionally, the expert's evidence presented at the hearing suggests that even at much higher levels, electric and magnetic fields do not pose a health hazard.

After reviewing all the evidence, the Board believes there would not be adverse health effects associated with the electric and magnetic fields of the proposed line.

The Board has reviewed the two alternatives suggested by Mrs. van Ryn; however, there was no evidence introduced at the hearing to indicate that either of the alternatives offered overall advantages when compared to TransAlta's routes. With regard to Mrs. van Ryn's suggested eastern alternative, the Board notes that she was unable to obtain landowners' consent for this alignment.

The Board has examined the concerns presented by Mr. Z. Gergely regarding his plans to operate a helicopter school. It notes TransAlta's agreement to modify the line's structural profile so as to accommodate Mr. Z. Gergely's preferred glide path and meet Transport Canada's regulations. The two-pole configuration would thus allow co-existence of the line and the proposed school.

The Board believes that an 8 per cent glide path can be achieved with TransAlta's option 2 by lowering the structure profile to approximately 10 m (32 ft). This is illustrated in figure 3. The route preferred by TransAlta would therefore be acceptable.

In the Board's opinion, at those locations where the heliport glide path would pass over the proposed 138-kV transmission line, TransAlta should use the structures specified for option 2 to keep the transmission line at or below Transport Canada's recommendation for heliport glide paths. The placement of such structures, with respect to the glide path, is a decision that should be made between TransAlta and Mr. Z. Gergely, since there are presently no actual defined approach paths to the proposed helipad.

The Board notes Mr. J. Gergely's concerns about visual impact and interference to irrigation due to the proposed line. The Board does not believe that the proposed line would cause a major visual impact because it would be situated approximately 270 m from his home. Regarding Mr. J. Gergely's concern over interference to his irrigation system, the Board notes that TransAlta has agreed to design and build the line so as not to interfere with it.

6 CONCLUSION

The Board believes that the proposed line is needed and should be approved. After reviewing all the evidence, it does not believe that the effects of Alternative 1, as compared with those of Alternative 2, would be severe enough to justify the increased cost of some $336 000. The Board therefore believes that the applicant's preferred route, with modifications to alleviate the irrigation concerns of Mr. Duban, Mr. Glover, and Mr. J. Gergely, and the helicopter concerns of Mr. Z. Gergely, is the most suitable.

7 DECISION

The Board decision is that Application 880963 be granted and that the preferred route, Alternative 1, be approved as set out in this report, subject to the undertakings made by the applicant at the hearing, including the following specific conditions:

a) Structural modifications shall take place along Mr. Duban's and Mr. Glover's property located in the northwest and northeast half of section 23, township 9, range 21, west of the 4th meridian, to allow the half section pivot irrigation system and future quarter section pivot irrigation systems to operate properly.

b) Structural modifications shall take place along the northwest quarter of section 33, township 8, range 20, west of the 4th meridian, similar to structures specified for option 2, as shown on figure 3. Sufficient two-pole structures, with a height of

no more than 10 m, shall be used to allow co-existence of the transmission line with the proposed helipad. The number and placement of these structures should accommodate Mr. Z. Gergely's proposed east-west flight path, as per Transport Canada's heliport standards. This requirement would be subject to minor variations should Mr. Z. Gergely modify the direction of his flight path prior to construction of the line.

c) Structural modifications shall take place along the northwest quarter of section 33, township 8, range 20, west of the 4th meridian, so that the two-pole structures allow the pivot irrigation system of Mr. J. Gergely to operate properly.

In the event that the parties cannot agree on the precise location of the structures as set out in the above clauses, the matter may be referred to the Board, and the Board will determine the locations of the structures.

DATED at Calgary, Alberta, on 2 February 1989.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

G. J. DeSorcy, P.Eng.
Chairman

J. P. Prince

J. P. Prince, Ph.D.
Board Member

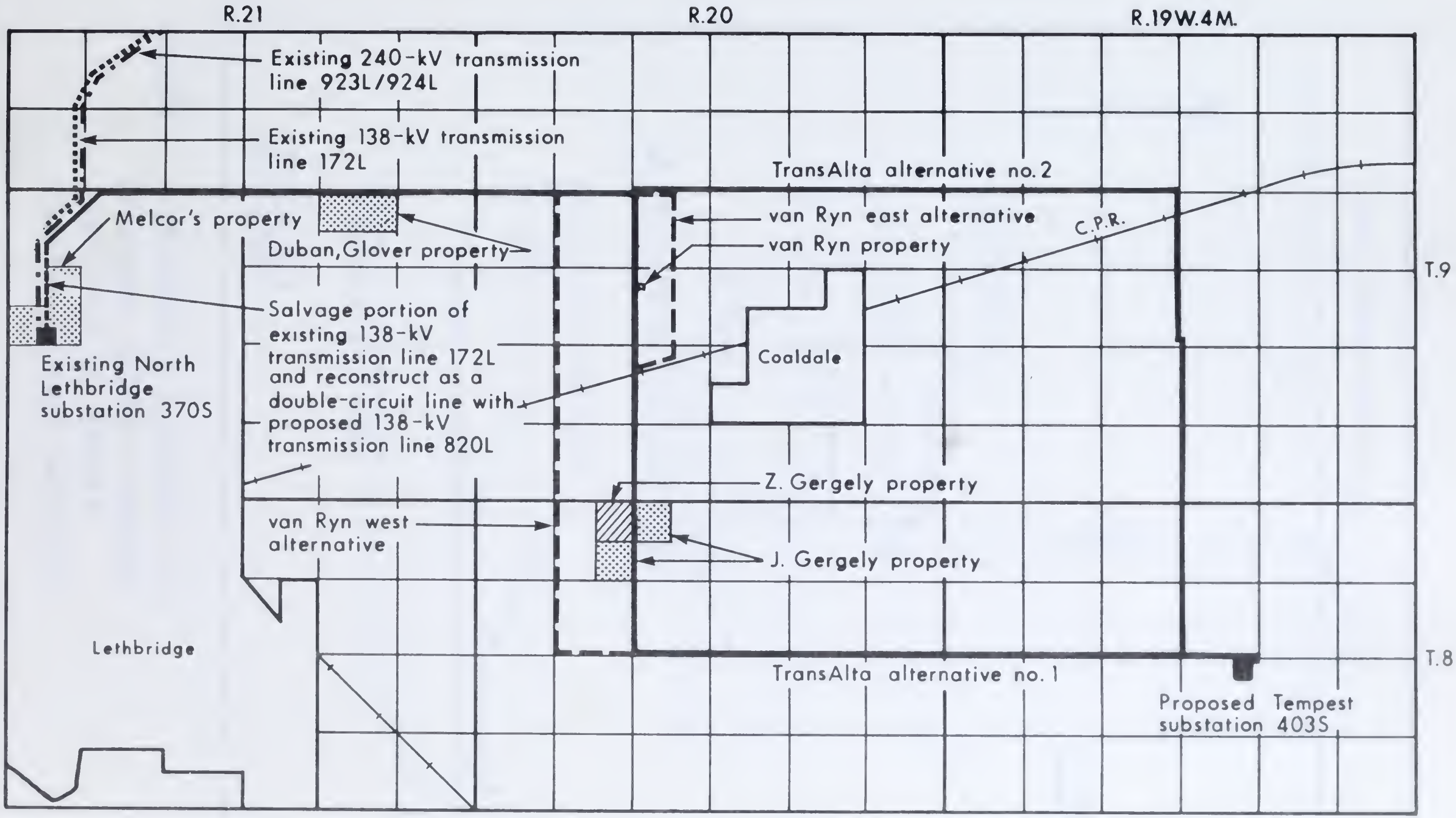


FIGURE 1 PROPOSED FACILITIES IN THE LETHBRIDGE–TEMPEST AREA
Application No. 880963
TransAlta Utilities Corporation

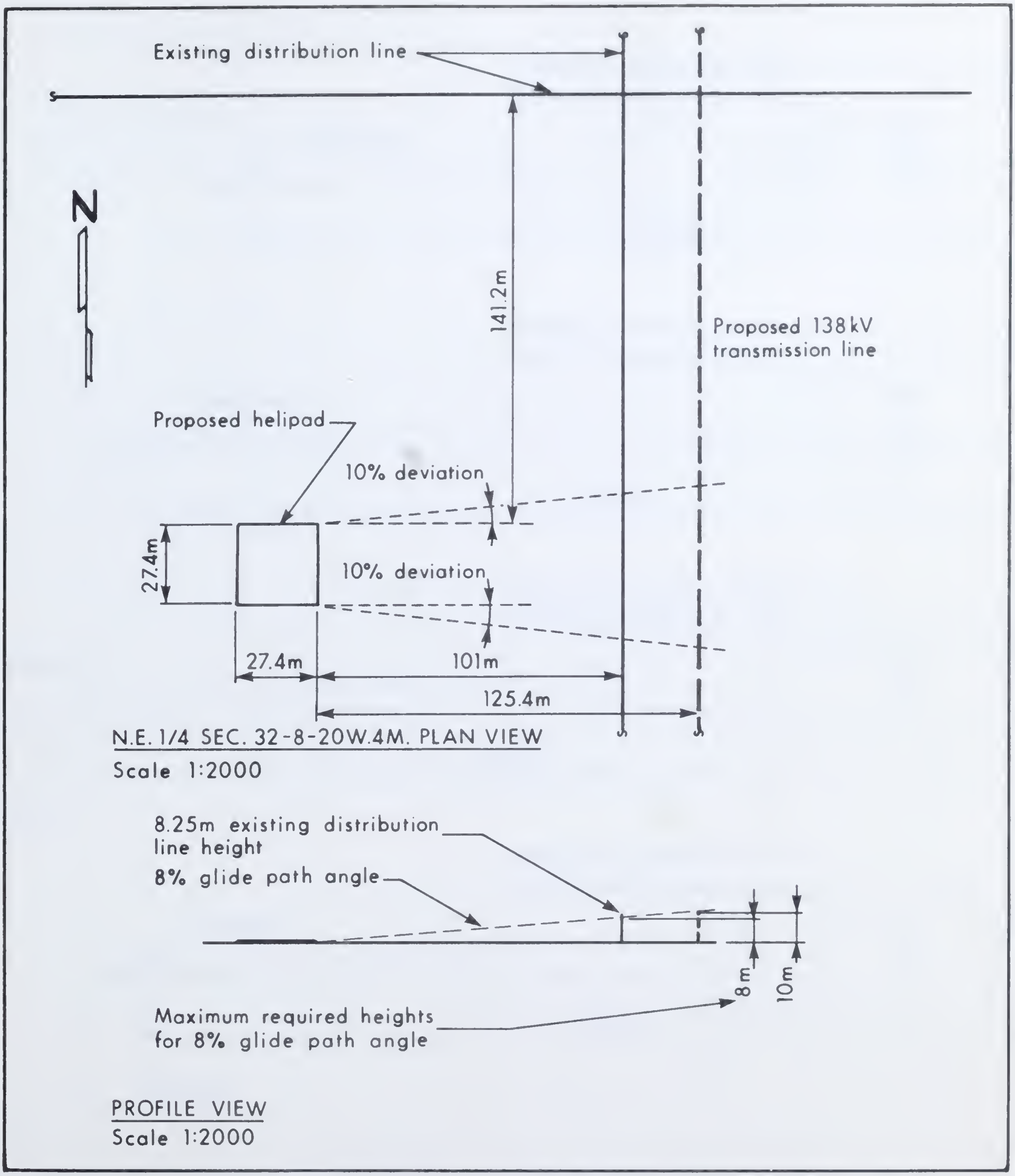


FIGURE 2 APPROXIMATE DISTANCES TO PROPOSED GERGELY HELIPAD
Application No. 880963
TransAlta Utilities Corporation

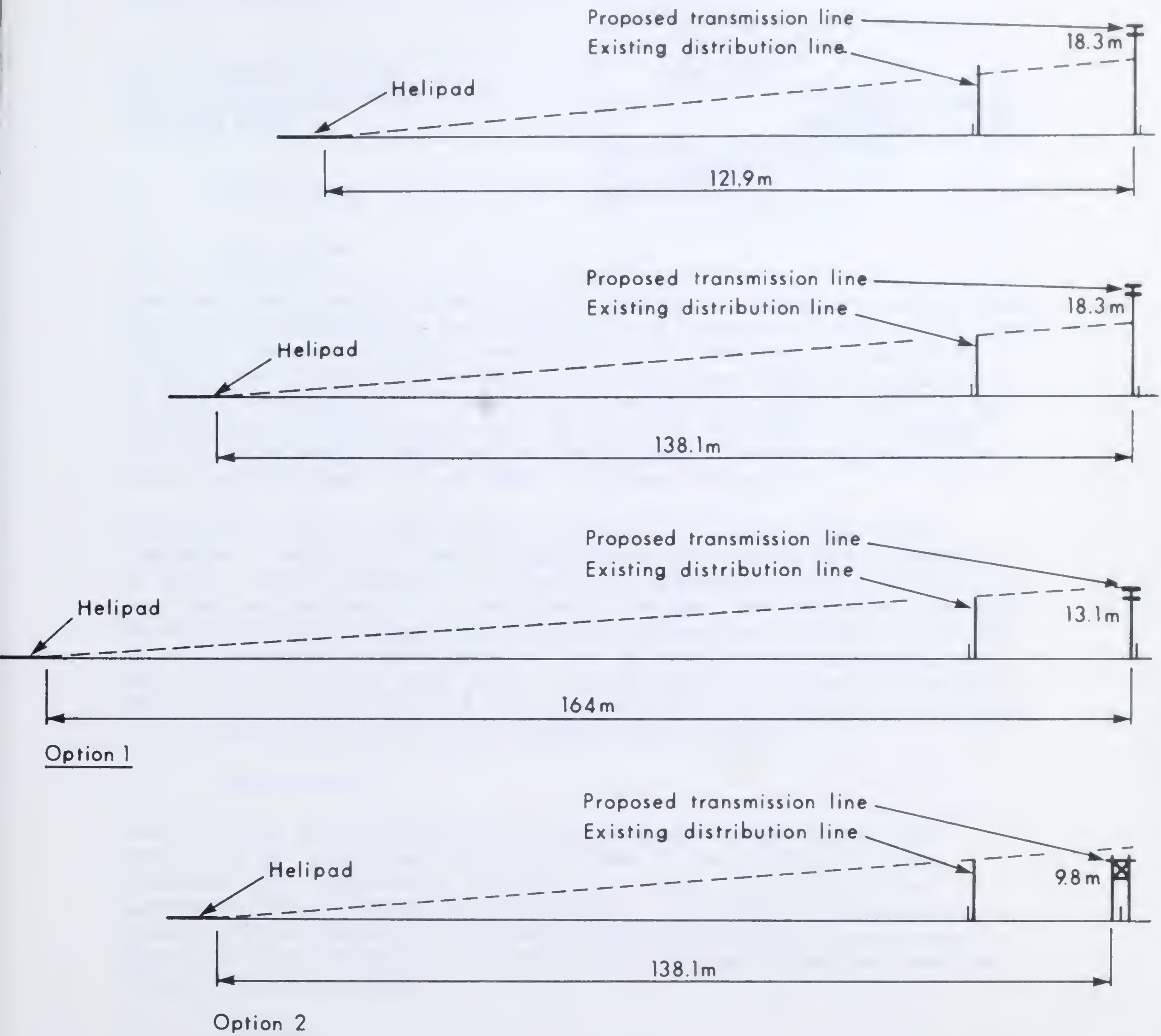


FIGURE 3 TRANSALTA'S OPTIONAL STRUCTURE CONFIGURATIONS
Application No. 880963
TransAlta Utilities Corporation

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

DOME PETROLEUM LIMITED
WELL LICENCE APPLICATION
WATERTON FIELD

Decision D 88-20
Application 880983

1 INTRODUCTION

1.1 Application

Dome Petroleum Limited (Dome) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a licence to drill a well from a surface location in legal subdivision 11 of section 8, township 6, range 2, west of the 5th meridian, to a projected bottom-hole location in legal subdivision 15 of section 8, township 6, range 2, west of the 5th meridian. The proposed well, to be known as DOME ET AL WATERTON 15-8-6-2 (the well), would be for the purpose of obtaining production from the Mount Head, Livingstone, or Wabamun Formation.

After submitting its application, but prior to the hearing, Dome completed a merger with Amoco Canada Petroleum Company Ltd. (Amoco). In their opening remarks at the hearing, representatives of the applicant stated that as a result of its merger Dome had ceased to exist as an operational company but continued to exist as a legal entity and as a corporation. Accordingly, if the application were approved, the well licence would be held in the name of Dome as an agent for Amoco. Amoco would operate the well and any commitments made by Dome throughout the licensing process would be complied with by Amoco.

1.2 Interventions

Interventions to the application were received by the Board from landowners and concerned persons who live in the vicinity of the proposed well, referred to collectively as the Beaver Mines Area Landowners Group (the Beaver Mines Group). An intervention was also received by the Board from the Lethbridge Fish and Game Association. Those who appeared at the hearing to speak to their interventions are identified in the table.

1.3 Hearing

A public hearing of the application was originally scheduled for 13 September 1988. Prior to the commencement of the hearing on that date, the Board received a request from the Beaver Mines Group for a postponement of the hearing to allow time for their expert witnesses to complete preparations of their position. The Board decided that, given the circumstances of the interveners and the delay in obtaining documentation by affected parties, the hearing would be re-scheduled to commence 27 September 1988.

The public hearing of the application was held in Pincher Creek, Alberta, on 27, 28, and 29 September 1988, before Board Members F. J. Mink, P.Eng. and E. J. Morin, P.Eng. and Acting Board Member J. D. Dilay, P.Eng. At the conclusion of Dome's formal presentation of its application, the hearing participants and the Board visited the proposed well locations and the general area.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Dome Petroleum Limited (Dome) R. A. Neufeld	D. M. Leahey, Ph.D. (of Western Research Division of Bow Valley Resource Services Ltd.) R. L. Laforge S. E. Montgomery, P.Eng. D. M. Huebner, P.Eng. J. G. Ward, Ph.D. S. H. Irving, P.Eng. D. A. Davison, P.Geol.
The Beaver Mines Area Landowners Group (Beaver Mines Group) J. S. Scarth	R. Andrist G. Petrone O. Petrone D. H. Sheppard, Ph.D. J. A. Sheppard E. A. Judd D. Cox M. J. Whelan M. Judd W. Judd H. Davis D. W. Mahood, MSc. (of Freshwater Research Limited) B. L. Horejsi, Ph.D. (of OK Biological Services Ltd.) D. M. Adams, MSc. (of Adams & Pearson Associates Ltd.)

THOSE WHO APPEARED AT THE HEARING (continued)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
	P. M. Dranchuk, Ph.D. (of P. M. Dranchuk Petroleum Consultants Ltd.)
Energy Resources Conservation Board staff A. A. Broughton D. G. Beamer S. J. Smith, P.Eng. R. E. Turski, P.Eng. C. S. Richardson	

2 BACKGROUND

The proposed well would be located approximately 21 kilometres (km) west of the town of Pincher Creek and approximately 3 km west of the hamlet of Beaver Mines, along the eastern slopes of the Rocky Mountains. The area is characterized by high ridges and hills where mixed spruce and poplar forests occupy the eastern and northern slopes and some lower areas. There are broad valleys 1 to 2 km in width by several kilometres long, some of which are used for hay crops and cultivation in lower regions. Ranching is a primary industry in the area and as such, cattle range much of the upper slopes during summer months and are moved to lower areas in winter to preserve the natural grasslands and wildlife habitat of the upper areas. The oil and gas industry is also present in the area through its development of lease roads, gas well sites, and pipelines (Figure 1).

The primary geological zones of interest at the proposed well are the Mount Head and Livingstone Formations, which are collectively designated by the Board as the Rundle C Pool (the C Pool) in the Waterton Field. The pool has an areal extent of 9 sections, as shown on Figure 1. There are currently three wells producing gas from the C Pool: TEXACO CASTLE RIVER A-3-4-6-2 (3-4), TEXACO CASTLE RIVER B-6-17-6-2 (6-17), and TEXACO WATERTON 5-20-6-2 (5-20). The C Pool is typically gas bearing, with hydrogen sulphide (H_2S) being produced in concentrations up to 27.5 per cent. A secondary geological zone of interest in this area is the Wabamun Formation which also produces gas and has H_2S concentrations up to 28.8 per cent.

In its application, Dome assumed the proposed well would have an H_2S concentration of 25.84 per cent and calculated a potential H_2S release rate of 0.7799 cubic metres per second (m^3/s) for the C Pool. Also, it assumed an H_2S concentration of 28.82 per cent and calculated a potential release rate of 2.1287 m^3/s for the Wabamun Formation. On the basis of these potential release rates and the proximity of the proposed well to area residents, the Board has classed this well as critical.[1]

3 ISSUES

The Board considers the issues with respect to the application to be

- the need for the well,
- the bottom-hole location of the well,
- the impacts of the proposed and alternative surface locations for the well, and
- the adequacy of the drilling plan and the emergency response plan with respect to public safety.

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[1] A critical sour well is defined in ERCB Interim Directive ID 87-2, Sour Well Licensing and Drilling Requirements, as

(1) any well from which the maximum potential H_2S release rate is 0.01 m^3/s or greater and less than 0.1 m^3/s and which is located within 500 m of the corporate boundaries of an urban centre, or

(2) any well from which the maximum potential H_2S release rate is 0.1 m^3/s or greater and less than 0.3 m^3/s and which is located within 1.5 km of the corporate boundaries of an urban centre, or

(3) any well from which the maximum potential H_2S release rate is 0.3 m^3/s or greater and less than 2.0 m^3/s and which is located within 5 km of the corporate boundaries of an urban centre, or

(4) any well from which the maximum potential H_2S release rate is 2.0 m^3/s or greater, or

(5) any other well which the Board classifies as a critical sour well having regard to the maximum potential H_2S release rate, the population density, the environment, the sensitivity of the area where the well would be located, and the expected complexities during the drilling phase.

4 NEED FOR THE WELL

4.1 Views of the Applicant

Dome submitted that there is a need for the well in order that it may recover its share of reserves, to prove up and conserve those reserves, and to gain information on the area geology. It stated that some of the reserves it believes underlie section 8 are being drained by the 6-17 well which the proposed well would capture if it were drilled. Further, Dome had approached Texaco in November 1987 with a request to pool section 8 with section 17. Texaco responded that it would pool only if Dome were to prove up its reserves. Therefore Dome contended that it is essential to drill the proposed well in order to prove up those reserves. Dome also stated that it estimates approximately 165 million cubic metres, or 18.9 per cent of producible reserves, would not be recovered from the pool if the well were not drilled, and this establishes a need for the well for conservation reasons. Further, Dome submitted that the well is needed to obtain geological information that would better define the areal extent and the productive capabilities of the C Pool and the Wabamun Formation.

With respect to economic viability, Dome stated that this project is only marginally economic. Its economic evaluation was based on a completed well cost of \$3.34 million, and revenues of \$38.18 million collected over about 30 years. Dome stated that a re-examination of the proposal's economic feasibility would be necessary if the ERCB required it to run intermediate casing to the Mount Head Formation at an incremental cost of \$400 000.

4.2 Views of the Interveners

Several of the interveners questioned the need for the well. Mr. R. Andrist stated that the well should not be allowed to be drilled when the pool is already being drained by another well in the area. He further stated that, if the proposed well were to tap new reserves, he would be in favour of drilling. Dr. D. H. and Mrs. J. A. Sheppard believed the pool is being effectively drained by existing wells. They believed that any economic benefits from the well would not outweigh the risks to public safety and the aesthetic and environmental damage that would be caused by drilling and producing the well. Mrs. E. A. Judd also questioned the need for another well when there are currently several wells in the area that are draining this pool. Mrs. Judd further expressed deep concerns regarding the safety of her family and local residents and stated that the need for the well does not outweigh those safety impacts and concerns. Mrs. M. J. Whelan agreed with the other interveners that this well is not needed when the pool can be exploited by existing wells and she supported their arguments that the need for the well is not greater than the negative impacts on the environment and local people. Mrs. W. Judd suggested that Texaco should be required to pool with Dome and that production from section 8 should be allowed from Texaco's 6-17 well. She stated that this would

eliminate the need for the proposed well altogether. Mrs. W. Judd also agreed with the other interveners that the proposed well would have significant negative environmental, aesthetic, safety, and health impacts that would weigh heavily against the need for the well.

An expert witness for the Beaver Mines Group, Mr. D. M. Adams, concurred with Dome's submission that incremental reserves would likely be produced by the proposed well if it were drilled. He stated that, considering the heterogeneity and low permeability of the reservoirs, some incremental reserves would be recovered and as such, there would be a need for the well.

In regard to the economics of the well, the Beaver Mines Group stated that any subsurface resource benefits would be exceeded by surface costs, such as environmental impact costs. Addressing the benefit to Albertans through collected royalties and taxes, it argued that it was possible that freehold production from the applied-for well would be in lieu of production from offset wells, some of which are on Crown land.

4.3 Views of the Board

The Board recognizes that there is a need for the proposed well in order to evaluate the hydrocarbon potential of the C Pool and the Wabamun Formation in section 8, to allow Dome to prove up and produce its share of reserves, to increase the ultimate recovery from the pool, and to gain geological information on the formations in the area. The Board believes that Dome's estimate of incremental recovery may be optimistic, but believes that a significant portion of reserves under section 8 could not be produced if the well were not drilled. The Board believes there is justification and need for the proposed well and that it could be proceeded with provided that it is drilled and operated in a manner that ensures the safety of the public and minimal impact on the environment and area residents.

The Board accepts Dome's contention that the applied-for well would be economic. The Board also agrees with the landowners that the cost of surface disturbances must be weighed against the benefits of extracting the subsurface gas reserves. Additionally, the Board accepts that some of the reserves underlying the freehold section may be recoverable from offsetting wells on Crown land so that direct monetary payments to the Alberta Government in the form of taxes and royalties may actually be greater if the proposed well is not drilled. However, the Board is required by section 4(d) of the Oil and Gas Conservation Act "to afford each owner the opportunity of obtaining his share of the production of oil or gas from any pool". Therefore the Board cannot discriminate in favour of the Crown over freehold rights. Additionally, the Board believes that the impacts of the proposed well on employment, future development, and other spin-off benefits to Albertans must also be considered, as must the economic cost or benefit to the subsurface mineral owner of proceeding or not proceeding with the project.

The Board notes that the applicant has obtained the consent of the landowner directly impacted by the proposed surface disturbance. The Board is satisfied that the drilling of the proposed well would represent a substantial economic benefit to Alberta and, subject to consideration of environmental, safety, and other matters, should be approved.

5 BOTTOM-HOLE LOCATION OF THE WELL

5.1 Views of the Applicant

Dome stated that it chose a bottom-hole location based on seismic data and information obtained from offset wells. It believed that the 5-20, 6-17, and 3-4 wells all encountered a single continuous thrust sheet which contains gas pools in the Mount Head, Livingstone, and Wabamun Formations. Dome believed that the reservoir quality of these formations improves to the north and that the formations at the proposed bottom-hole location are significantly higher structurally than farther south. Dome stated that this makes the northeast quarter of section 8 the most desirable bottom-hole location from a reservoir perspective. Dome further believed that there is about a 75 per cent probability of encountering commercial quantities of gas at the proposed bottom-hole location.

Dome stated that limited flexibility in the bottom-hole location exists; distances of 100 to 200 m in the north/south direction and 300 to 400 m in the east/west direction were suggested. Dome emphasized that these numbers represented drilling tolerances, and that the geologic target is a specific point - the proposed bottom-hole location. It also suggested that a surface location move of approximately 100 m in a northeast direction would not present a major adverse impact on reaching the target bottom-hole location of the well.

5.2 Views of the Interveners

In its submission, the Beaver Mines Group expert witness, Mr. D. M. Adams, agreed with Dome that while drilling, wells in the area tend to drift to the northeast and that section 8 is probably being drained by existing wells in the pool. He also agreed that the target formations are structurally higher to the northeast and that, geologically, the safest bottom-hole location would be in the northeast quarter of section 8.

5.3 Views of the Board

The Board notes that the geological interpretation of the Beaver Mines Group supported that of Dome and that both parties agreed that the best bottom-hole location would be within the gas target area of the northeast quarter of section 8. The Board also notes that, if it were deemed appropriate, a shift of surface location approximately 100 m

northeast would not have a significant adverse impact on the reservoir characteristics and recovery from the well, nor would it place the bottom-hole location outside the gas target area of the section.

6 IMPACTS OF THE PROPOSED AND ALTERNATIVE SURFACE LOCATIONS FOR THE WELL

In the course of the hearing, four surface locations were considered. These have been identified as Locations A to D as shown on Figure 2.

6.1 Views of the Applicant

6.1.1 Location A

Dome submitted that Location A, the applied-for surface location of the proposed well, was chosen taking into account the tendency for formations in the area to cause a well to drift to the northeast while drilling. This natural drift updip would cause the bottom-hole location to be approximately 150 to 200 m northeast of the surface location of the proposed well.

Dome believed that, if the well were drilled at Location A, little impact would occur on wildlife, Screwdriver Creek, or the interveners. Dome did, however, recognize the aesthetic concerns presented by the Sheppards and the concerns of the other interveners with regard to the proximity of its proposed location to Screwdriver Creek. Dome stated that Location A is an environmentally acceptable location that has been approved by Forestry, Lands and Wildlife, Fish and Wildlife Division. In recognition of the concerns expressed by the interveners, it had altered its original plans to use an on-site, in-ground sump and would be using steel tanks and a remote sump instead. Further, Dome submitted that it would fence the perimeter of the lease, would provide a diversion ditch to prevent runoff entering the lease, and would comply with all of the conditions imposed on it by Alberta Environment.

With respect to potential impacts on wildlife, Dome submitted that the proposed drilling site is not unusual if compared with many other well sites located on private and Crown lands along the eastern slopes and foothills. Dome further stated that the proposed and alternative locations are not significant wildlife habitat as most elk in the area winter at least 1000 m away on a ridge on the opposite side of the valley from the proposed well. Dome further submitted that, in addition to those of the oil and gas industry, impacts on wildlife occur from the main road through the area, pasturing of livestock, hunting, and existing residences.

6.1.2 Location B

Location B was adopted by Dome in an attempt to alleviate the concerns of the Sheppards and some of the concerns of the other interveners.

Dome stated that the re-surveyed site B would move the well an additional 100 m from Screwdriver Creek and the view of the well site from the Sheppard's house would be screened with heavy brush. It was prepared to utilize this site if it were deemed appropriate by the Board.

Dome believed that at Location B, approximately 100 m northeast of the proposed surface location, the bottom-hole location of the well would shift approximately 100 m to the northeast. It believed this would not have a significant detrimental effect on the gas recovery and reservoir properties, nor would it place the well outside the gas target area for the section. Dome did express a concern that a move greater than 100 m northeast might result in a bottom-hole location outside the gas target area.

6.1.3 Location C

Location C was suggested by a member of the Beaver Mines Group as a second alternative surface location approximately 150 m east of the proposed surface location. Dome submitted that, if it were to move to C, the bottom-hole location of the well would be on the edge of Dome's geological objective and the risks associated with drilling the well would be increased. It stated that this would require directional drilling in order to keep the well as close to its bottom-hole objective as possible.

Dome believed that Location C presented more serious construction problems and adverse environmental impacts than both Locations A and B. Because of the increased surface relief at the location, Dome contended that there would be a larger cut into the hillside and severe drainage problems on and around the lease.

6.1.4 Location D

Location D was a third alternative surface location as suggested by an expert witness for the interveners, Dr. B. L. Horejsi. It would correspondingly shift the bottom-hole location of the well farther north than Dome's proposed alternative location. Dome submitted that it does not want to overshoot its gas target area and that a move to D would require directional drilling to maintain the bottom-hole location within the gas target area.

6.1.5 Other Impacts

Dome did not consider surface Locations C and D as appropriate alternatives because of the implications these sites presented to the successful drilling of the well. It submitted that the costs associated with directional drilling and the additional time the wellbore would be left open to the critical zones while drilling do not make Locations C and D practical alternatives.

In addressing the concerns expressed with respect to ground-water pollution and percolation of lease fluids to Screwdriver Creek, Dome submitted that it would perform water well tests for local concerned residents and, if required by the Board, perform a standard water quality test on Screwdriver Creek to obtain baseline data prior to drilling operations. It also believed that there is no chance of water well problems occurring considering the distance from all four locations to those water wells and the fact that Dome will set 100 m of surface casing and 945 m of intermediate casing in the well. Notwithstanding that position, Dome was prepared to test the Sheppards' water well to provide a baseline for future reference.

Dome believed that the proposed and alternative locations do not pose a threat to the long-toed salamander or spotted frog populations in the area. It stated that there are no pools of water (required by these amphibians for reproduction) at any of the locations.

Dome stated that road dust control would be provided by the local municipality for any of the proposed surface locations, and Dome would be back-billed for those dust control measures. Dome noted that concerns about the type of dust control agent to be used on the municipal road should be directed to the municipality, which would be responsible for selecting the agent.

With regard to safe operation of vehicles by Dome personnel on the municipal road, Dome emphasized that it was its policy to ensure that company owned and operated vehicles are operated in a safe and prudent manner.

6.2 Views of the Interveners

The interveners contended that there would be serious environmental, safety, and aesthetic impacts if the proposed well were allowed to be drilled at any of the locations under consideration.

6.2.1 Location A

With respect to the proposed Location A, the Beaver Mines Group stated that this location presented the most serious potential impacts. Concerns were raised with respect to contamination of Screwdriver Creek from sump and other fluids flowing from the lease, loss of wildlife from the general area, noise, light and visual impacts that would diminish the quality of life for the interveners, negative effects on property values, increased unauthorized access to adjacent properties, historical resources impacts, and water pollution from seepage through the lease into Screwdriver Creek.

The Beaver Mines Group believed that Dome had not adequately addressed the issue of impact of the proposed well site and associated activities on large mammals, such as elk, and on long-toed salamanders and spotted

frogs. It submitted that there is a large amount of evidence available that confirms that elk are affected by oil and gas exploration and development. Further, many of the members of the Beaver Mines Group stated that they have noticed a sharp decline in elk populations since oil and gas activities started in the area. The Beaver Mines Group suggested that, to minimize impacts on large mammals, Dome should provide a canvas shield around the rig floor, use an electric rig, and bus the drilling crews from a rendezvous point in Beaver Mines. Dr. Horejsi contended that the long-toed salamander and the spotted frog are two rare species that occur in this area and they could be severely impacted by the proposed well.

6.2.2 Location B

The interveners stated that Location B as proposed by Dome would alleviate some of their concerns. The moving of the lease to 100 m from the creek and the elimination of the on-site sump provided additional assurance to the interveners that the possibility of contamination of the creek would be decreased. Nevertheless, the interveners remained concerned that there could be contamination through the subsoil. Also, Location B provided some screening of the well site because of the existing poplar cover.

6.2.3 Location C

A member of the Beaver Mines Group suggested Location C as an alternative surface location and C was endorsed by the members of the group. Location C would be approximately 150 m directly east of the proposed surface location and would result in a corresponding shift of the bottom-hole location 150 m east. The intervener submitted that this bottom-hole location would remain within the gas target boundary for the section. It was further stated that this location resulted from consideration of the interveners' concerns and then choosing a location that would best alleviate those concerns. The Beaver Mines Group submitted that Location C would provide the maximum amount of natural screening of the well site, would be approximately 150 m from Screwdriver Creek, and would reduce noise and impacts on wildlife.

6.2.4 Location D

Location D, as proposed by Dr. Horejsi, was chosen from strictly a wildlife-habitat-preservation perspective. He submitted that this would shift the well location approximately 200 m north of Dome's proposed alternative but the well would still remain within the gas target area for the section. Dr. Horejsi stated that Location D is in open grassland and would not result in destruction of wildlife habitat by the removal of tree cover. He stated that temporary ponds could well exist at Locations A, B, and C, and that the impacts on the long-toed salamander and the spotted frog could be minimized by moving the well away from Screwdriver Creek to Location D. Dr. Horejsi stated that Location D was chosen as the best location to minimize wildlife impacts

and the Beaver Mines Group stated that in choosing Location C, those impacts were taken into consideration.

6.2.4 Other Impacts

It was the position of the Beaver Mines Group that for Location A, B, or C, Dome should be required to seal the surface of the lease with an impermeable clay barrier. It believed that this would prevent the penetration of lease fluids into the subsoil and water table.

6.3 Views of the Board

The Board evaluated the proposed surface location and the alternative locations with consideration for visual screening, impacts on Screwdriver Creek, safety, lease construction, impacts on wildlife and amphibians, and the bottom-hole location of the well.

6.3.1 Location A

Although the proposed surface location has been approved by Alberta Environment and Dome has decided to utilize a remote sump, the Board recognizes some of the ongoing concerns expressed by the Beaver Mines Group with regard to this location. The Board accepts the argument that moving the location away from Screwdriver Creek will reduce the potential for accidental impacts on the stream ecosystem and that a move would also reduce the visual impacts on the interveners.

6.3.2 Location B

The Board notes that the edge of the lease for alternative Location B is approximately 100 m from Screwdriver Creek and the site is located in a poplar grove, which would mitigate two major concerns expressed about site A. The Board further notes that Dome is prepared to accept Location B if deemed appropriate and that this location poses no adverse effects on lease construction, drilling, the bottom-hole location relative to gas target area, reservoir properties, and ultimate recovery from the well. The Board believes this site offers some advantages over site A.

6.3.3 Location C

The Board believes that Location C as proposed by the Beaver Mines Group may present more severe environmental impacts and construction problems than the proposed location or alternative Locations B and D. The Board notes that this location is on a side hill that would involve cut-and-fill lease construction and may create potential for drainage and erosion problems. It also believes that the visual impact from the proposed well at Location C will be minimally reduced from that at

Location B and may indeed be increased as a result of soil build-up on the lower side of the lease.

The Board also notes that Location C may cause the bottom-hole location to move outside of Dome's geological objective and as such, increase the risks associated with drilling the well. Further, if directional drilling were required to control the deviation of the well, the costs involved would increase and the critical zones would remain open for an extended period of time.

The Board notes that impact on wildlife was also a consideration of the Beaver Mines Group in choosing Location C. On the basis of Dr. Horejsi's evidence, the Board understands that to minimize impacts on wildlife the location would have to be removed entirely from the poplar stands. Thus there appears to be no difference between alternative Locations B and C in this respect. The Board also notes that the interveners contended that elk populations are viewed on the ridges to the north of the well site in winter months and do not venture south to the proposed well site area. Given the limited area involved and the established impact on wildlife due to other industrial and agricultural activity, the Board believes it would be more prudent to use the treed area to screen the well site. The Board does not believe that the long-toed salamander and spotted frog would be affected by the drilling and normal operation of the well, although it does believe that Location B presents less potential for impacts on these amphibians than does Location A.

6.3.4 Location D

The Board notes that Location D was not endorsed by the Beaver Mines Group and although this location addressed the interveners' concerns over impacts on wildlife, it was chosen without regard for aesthetic, safety, and other environmental concerns that were expressed. Further, a shift of 200 m to the north would almost certainly place the bottom-hole location outside the gas target area unless deviation control were employed while drilling. The Board does not consider it to offer any significant advantages over the other sites proposed.

6.3.5 Other Impacts

There was a common concern for all four surface locations respecting noise and light impacts while drilling, sealing the surface of the lease, increased public access to adjacent properties, and impacts on historical resources. The Board accepts that, while drilling, noise and light from the rig may be heard and seen by residents in the area. However, this is of a temporary nature and should not preclude the drilling of the well. The Board also accepts that access to the well site will be restricted by Dome to only authorized persons. The Board believes that sealing the surface of the lease with an impermeable clay is not necessary as all fluids will be disposed of off lease and

any residual fluids will be of minor amounts and will not present an environmental hazard. The Board notes that Dome agreed to report and preserve any part of the site that is found to be archaeologically significant. The Board believes that measures imposed on Dome by the Board and compliance with the Oil and Gas Conservation Regulations will minimize impacts on landowners adjacent to the proposed well, and the possibility of adverse impact on property values.

It was suggested by Dr. Horejsi that the well not proceed until a population and impact assessment on the long-toed salamander and spotted frog had been completed. The Board notes that the nearest observance of the salamander to the proposed and alternative well locations has been the Sheppard residence approximately 800 m away. While it was submitted by Dr. Horejsi that the spotted frog commonly occurs with the salamander, there has been no observance of the frog in this area. The Board believes that, considering the proposed well site is well removed from the type of environment that typically offers habitation for these amphibians, and there has not been an observance of them in the vicinity of any of the well-site locations considered, it is very unlikely that there will be any impact as a result of drilling the well.

Having considered all aspects of the well locations, the Board believes site B offers the best overall solution to the concerns raised by all parties.

The Board notes that Dome had committed to an undertaking to secure the surface rights to Location B and on 21 October 1988 provided the Board with confirmation that it had secured those rights.

7 DRILLING SAFETY

7.1 Views of Dome

Dome indicated that it will prepare its drilling program directly from its detailed drilling submission and emphasized that its objective is to drill the well in a safe and efficient manner. To this end, its drilling submission complies in every way with the provisions of ERCB Interim Directive 87-2 and also complies with the Blowout Prevention Review Committee's (BPRC) Alberta Recommended Practices.

Regarding the specific points of concern set out by the Beaver Mines Group, Dome had researched drilling occurrence data from offset wells in the general vicinity to identify any potential drilling problems. From its findings, Dome concluded that it was not necessary to set intermediate casing down to the top of the Mount Head Formation. Dome submitted that surface casing set at 100 m and then a corresponding intermediate casing setting depth of 945 m would be more appropriate, as this would still allow the well to be drilled in a safe and efficient manner but at the same time significantly reduce the cost of drilling.

Dome also submitted that the BOP stack it intends to use while drilling the well is adequate. It pointed out that the pressure rating of the BOP stack of 34 500 kilopascals (kPa) is the working pressure but that the actual pressure to which the stack would have been tested is double that value, or 69 000 kPa. In response to concerns raised by the interveners, Dome indicated it does not believe that coring is an inherently dangerous operation but agreed that it requires special precautions. Dome submitted that its coring procedure includes those precautions; therefore coring operations in this well would be conducted in a safe manner.

7.2 Views of the Interveners

The Beaver Mines Group submitted that it was concerned with the length of intermediate casing Dome was proposing to set. It indicated that it would be much better to set intermediate casing to just above the Mount Head Formation. It suggested that this proposal would make any coring operation in the sour zones much safer because everything up hole would be behind pipe. The Beaver Mines Group felt that coring the sour zones with 945 m of intermediate casing in place would be very risky and unsafe.

The Beaver Mines Group also submitted it was concerned with the capacity of the BOP stack and casing bowl. It suggested that the pressure rating of both the BOP stack and casing bowl does not provide much of a safety factor considering the anticipated bottom-hole pressure for the Wabamun is 41 000 kPa. It did not indicate what a suitable rating for the BOP stack would be, but suggested that it would be dangerous practice to use Dome's proposed 35 000-kPa BOP stack in this case.

7.3 Views of the Board

The Board has reviewed Dome's detailed drilling plan and finds that it complies with current ERCB standards and regulations for safe design and drilling of critical sour gas wells. The Board notes that these standards had been developed, reviewed in detail, and adopted after extensive study following the Lodgepole Blowout Inquiry, and they are considered to be the most stringent standards in practice in the industry. The Board is therefore satisfied that the well could be drilled in a safe and efficient manner.

The Board notes that all the operative C Pool wells in the area have intermediate casing set to approximately 1500 m. If drilling is approved, Dome will be required to provide Board staff with an evaluation of the need for more than 945 m of intermediate casing after drilling down to but prior to entering the Mount Head Formation. This evaluation would be based on the integrity of the open hole and first intermediate casing, as well as drilling problems experienced, if any. The BOP stack Dome has proposed to use fully meets the requirements of ERCB regulations as well as the BPRC's Alberta Recommended Practices for

drilling critical sour gas wells. The Board therefore considers the proposed BOP stack to be adequate to drill the well safely. The Board also considers Dome's coring procedure to be satisfactory and believes that coring operations have been planned safely.

8 EMERGENCY RESPONSE PLAN

8.1 Views of the Applicant

Dome submitted that an extensive emergency response plan (ERP) had been prepared to completely protect the residents in the area. On the basis of the combined maximum H_2S release rates of the C Pool and the Wabamum, it calculated an emergency planning zone (EPZ) radius of 4.75 km from the well. This EPZ was divided into an inner zone 1 and an outer zone 2. Zone 1 has a planning radius of 2 km from the well, which was determined from the release rate of the C Pool only. Zone 2 extends from 2 km to 4.75 km and was determined from the combined release rates of the C Pool and Wabamun Formation.

Dome stated that after reviewing its ERP in greater detail, it decided to amend the plan so that there would be no differentiation in the stages of alert for the C Pool and Wabamun Formation. It submitted that its finalized ERP will reflect that the well has been deemed critical and the ERP would be put into effect when the C Pool is open, rather than only when the C Pool and Wabamun are open, as originally proposed.

Dome stated that, in its ERP, at a stage one alert there is no release of H_2S at the well site and residents in the EPZ are contacted. Its plan calls for vehicles to be dispatched to each and every residence in the EPZ so that if contact to residents by phone or personal pager is not possible, residents would be contacted in person by Dome personnel. Dome would provide transportation to the evacuation centre for any EPZ residents that required it.

Dome stated that in the event of a release of sour gas, the well would be ignited if 20 parts per million (ppm) of H_2S averaged over 20 minutes is being experienced in an unevacuated area and well control cannot be gained in a short time. Further, it stated that it would ignite the well if there were any doubt as to the safety of area residents or if required to do so by the Board. Dome said that the destruction of the rig resulting from ignition would play no part in consideration of the area residents' safety.

Dome maintained that the EPZ radius for the C Pool should be set at 2 km based on its H_2S content of 25.84 per cent and absolute open flow (AOF) rate of 260.2 E3 m^3/day (260 200 m^3/d).

8.2 Views of the Interveners

The Beaver Mines Group were concerned that, in the event of a blowout, safe evacuation would not be possible particularly if severe weather conditions would prevent vehicle travel. They were also concerned that the phone alert plan would be inadequate because of the local party-line system and they feared that, with only one route out of the valley, several of the local residents would have to pass the well site to escape the area.

The Beaver Mines Group also expressed concern about Dome's proposed ignition criteria. The Group was not confident that Dome would ignite the well and therefore destroy a very expensive drilling rig to protect the public. Dr. Dranchuk believed the ignition criteria proposed by Dome should be more stringent, such as the Board had accepted for ERPs in other areas.

Dr. Dranchuk also stated that the planning zone for the C Pool should be enlarged to 3.06 km in order to correspond with the larger release rate of 1.524 m^3/s which is a product of his estimates for the C Pool H_2S content (25.84 per cent) and C Pool AOF rate (509.7 E3 m^3/d).

8.3 Views of the Board

The Board notes that, if the application were approved, before the well is licensed a finalized ERP would need to be submitted to the Board for approval. Therefore, modifications to the ERP can be made based on the hearing evidence. Although Dome stated that Location B does not include any new landowners in the EPZ, the Board notes Dome's agreement includes in its ERP any additional landowners in proximity to its EPZ who may want to be notified and evacuated in case of an emergency.

The Board believes that the C Pool AOF value chosen by Dome is appropriate for the purpose of emergency planning. The AOF test in question provides a margin of safety, as the value of 260.2 E3 m^3/d is a stimulated sandface flow rate from an undepleted reservoir through a well which encountered more net pay than the proposed well is likely to. If a blowout did occur at the proposed well, it would be from an unstimulated well and a partially depleted reservoir. Also, the EPZ radius recommended in ID 87-2, Figure 6-1, using Dome's C Pool data is 1.90 km. This is exceeded by Dome's chosen EPZ radius of 2.0 km.

The Board notes that the reliability of paging units for evacuation of residents was questioned by the interveners. The Board is satisfied that pagers would not be relied upon as a first line of communication to the residents. Given that Dome intends to use paging only as a first alert system and to follow it up by driving to all residences in the EPZ to complete evacuation, the Board believes satisfactory measures are in place to assure the safety of the people in the area.

The Board believes that the ERP proposed by Dome is reasonable and practical and will provide for the safety of the residents under the various circumstances which are of concern to the Beaver Mines Group. It appeared at the hearing that some aspects of the plan were not well understood by the local residents; accordingly, the Board believes that in recognition of their concerns, Dome should meet with the members of the Beaver Mines Group prior to penetration of the critical zone to review the procedures in the ERP.

In reference to Dr. Dranchuk's suggestion that the ignition criteria should be more stringent, the Board believes that Dome's criteria is acceptable. The criteria used by Dome is the same ignition criteria typically considered suitable by the Board for most critical wells and is also the ignition criteria typically applied to wells with even higher release rates. Additional criteria, such as a 1-ppm level for 1 hour is normally used in conjunction with urban centres that are not practical to evacuate.

The Board expects that, should a release of H_2S occur that may otherwise endanger the lives of the public, Dome will ignite the release. Furthermore, the Board has the authority to order such an ignition and would do so if the safety of the public could not be assured.

9 DECISION

The Board has carefully considered and weighed the evidence presented at the hearing with respect to need for the proposed well and the impacts it presents to area residents, wildlife, the local environment, Screwdriver Creek, and safety and aesthetic considerations. The Board believes that many of the impacts can be mitigated by the choice of an appropriate surface location that will not severely impact the purpose, drilling, production target, and reservoir characteristics of the proposed well. The Board is confident that Location B proposed by Dome as an alternative surface location meets those requirements. The Board is also confident that the well can be drilled and operated without compromise to public safety and that Dome's emergency response plan will ensure the public's safety in the event of a mishap.

The Board therefore grants the application for a well licence at the alternative surface Location B proposed by Dome subject to all the commitments made by Dome in its application and at the hearing, and specifically to the following conditions:

- All drilling and lease fluids shall be contained in steel tanks for disposal at a remote sump.

- Dome shall perform a baseline water quality test of Screwdriver Creek prior to commencement of drilling operations. Results should be made available to the Department of Environment, the Board, and the Beaver Mines Group.

- o Dome shall perform a water well test on the Sheppard's well prior to commencement of drilling operations. Results should be made available to the Sheppards.

- o Dome shall submit a finalized emergency response plan to the Board prior to commencement of drilling operations and shall review those plans with concerned area residents prior to penetration of the critical zone.

DATED at Calgary, Alberta, on 1 February 1989.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Board Member

B. J. Morin, P.Eng.
Board Member

J. D. Dilay, P.Eng.
Acting Board Member

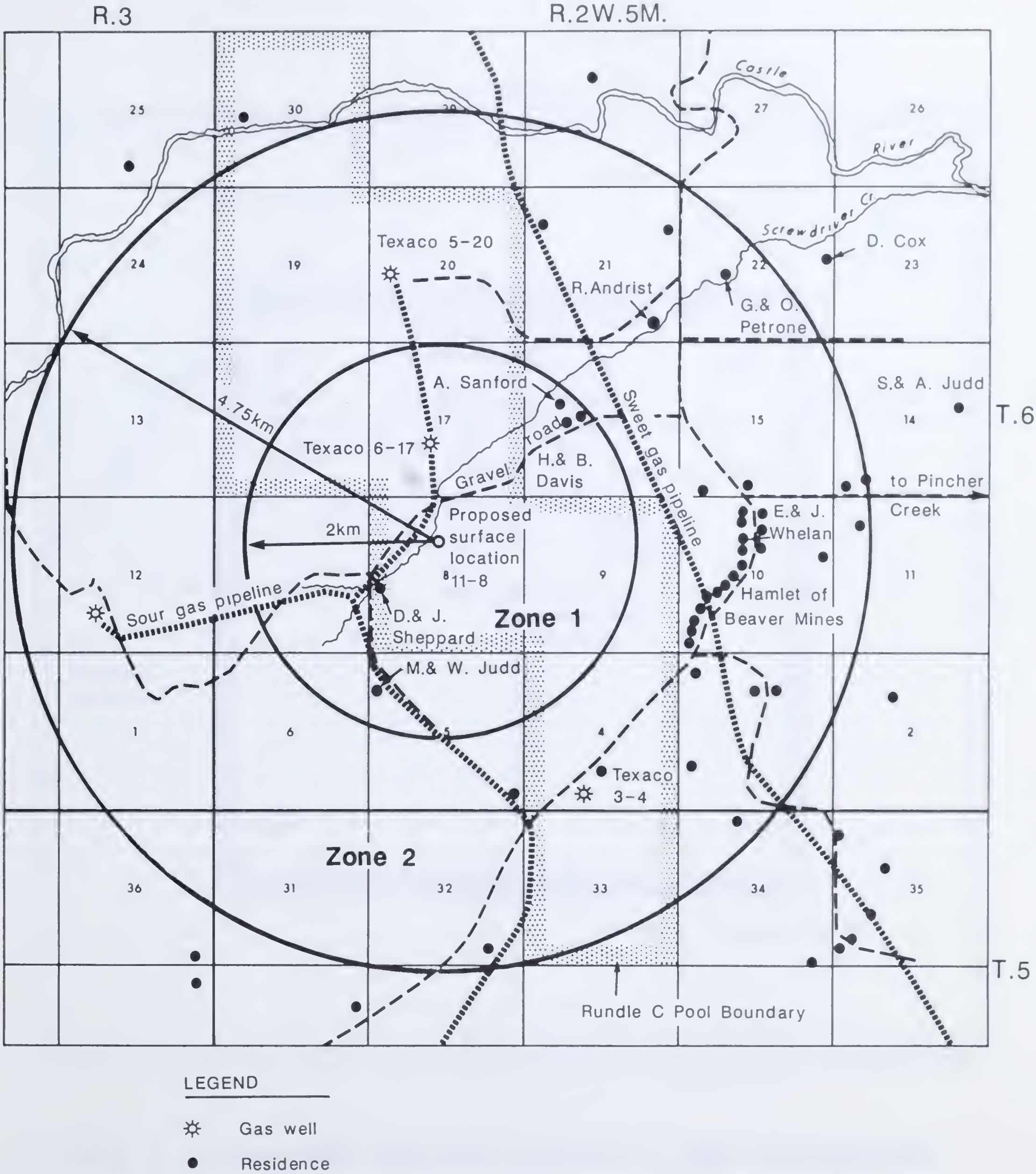

FIGURE 1 EMERGENCY PLANNING ZONES AND RESIDENCES

APPLICATION NO.880983

DOME et al WATERTON 15-8-6-2

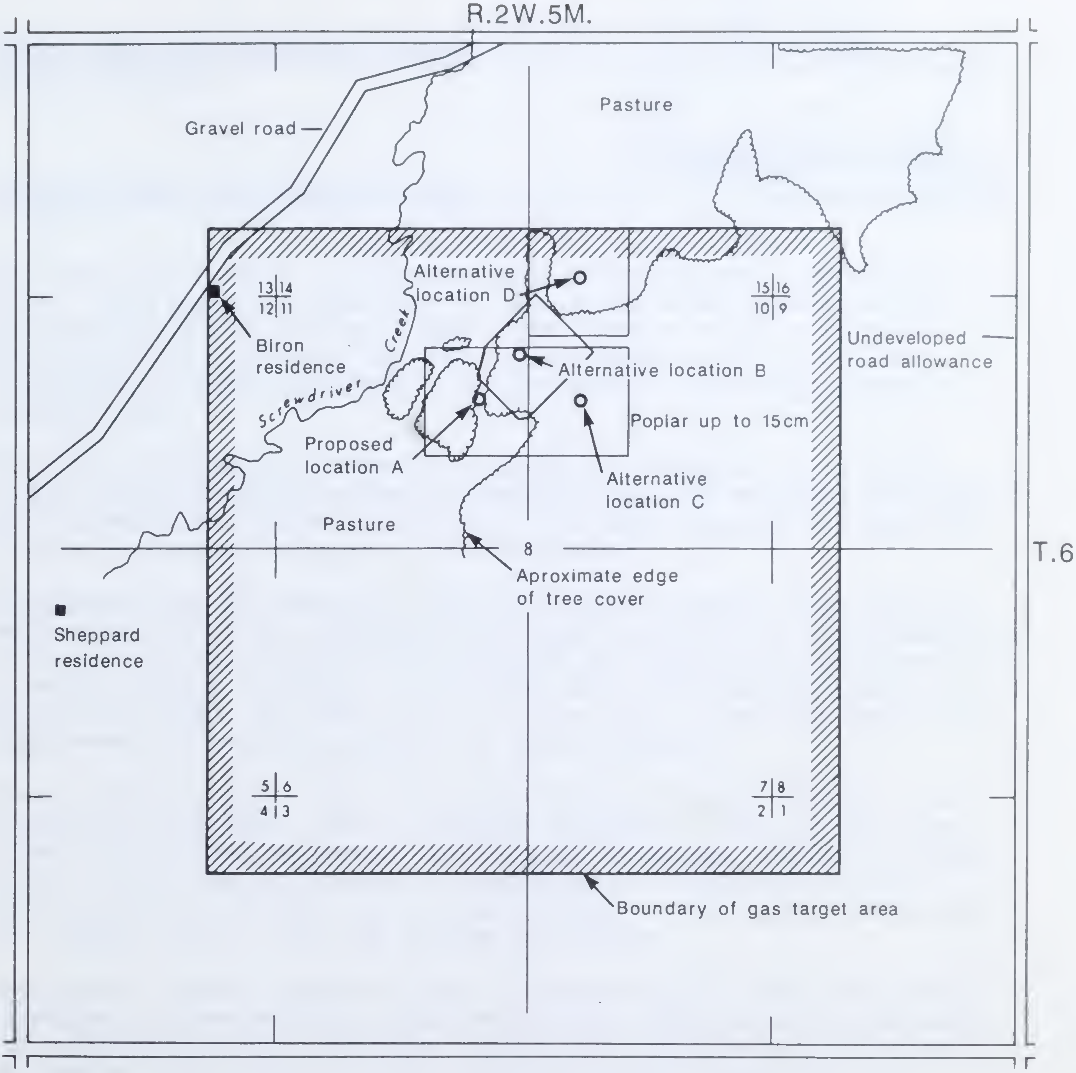

FIGURE 2 **PROPOSED SURFACE LOCATION A AND ALTERNATIVE LOCATIONS B,C, AND D FOR DOME et al WATERTON 15-8-6-2**

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CAMPBELL-NAMAO GAS PROCESSING PLANT

Memorandum of Decision
Application 861041

The Board has received a submission (from Norcen) to amend Application 861041 for a gas processing plant originally heard and recommended for approval by the Board in March 1987. The amendment would provide for installation of facilities for the complete removal and recovery of sulphurous compounds contained in the raw gases to be processed in its proposed plant.

The Board understands that Norcen reviewed the proposal to install the Lo-Cat sulphur recovery process extensively with area residents from April 1988 through June 1988 as the key part of a draft agreement intended to resolve outstanding concerns of area residents.

Recognizing that SO_2 emissions from the original proposed plant was the main issue that led to objections from area residents at a Board Hearing in March 1987 and believing that it had heard and ruled on other matters (such as noise, odours, corrosion, and location in a relatively populated rural residential area), the Board was of the view that the amended application might meet with general acceptance by area residents.

Based on the foregoing, the Board convened a pre-hearing meeting on the evening of 8 September 1988 at the Namao Elementary School to hear the views of interested residents, including the Roseridge Citizens Committee (RRCC), respecting the potential acceptability of the amended plant facility and the possible need for re-opening the hearing to consider any new concerns arising from the revised application.

When asked to address these matters, the RRCC indicated that there were diverging opinions among its large membership. While it recognized that the question of sulphur emissions had now been substantially addressed by the amended application, it still perceived concerns regarding

1) use of prime agricultural land (3.67 acres) for the plant,
2) the presence of such a plant in a relatively populated rural area, and
3) potential for and effects of increased future throughput through the amended facility.

Representatives of the RRCC at the meeting also noted that the views of the membership at large had not been received because of the limited time available to prepare for the meeting. Other nearby residents to the proposed plant site questioned Norcen regarding such matters as

4) emergency shutdown,
5) plans for an emergency response plan,
6) frequency and duration of flaring and sulphur emissions during upset conditions,
7) noise impacts,
8) the kinds of vapours that would be emitted through the stack when utilizing the Lo-Cat process,
9) the likelihood and frequency of noxious odours,
10) ERCB's specification of plant performance standards and enforcement of those standards by shut-in or prosecution,
11) fresh water requirements,
12) potential impacts of emissions on honey producing operations,
13) whether other small processing plants, producing wells, and pipelines would continue to proliferate in the area, and
14) potential increased conflict between the expanding rural residential population and additional petroleum facilities.

Norcen took the position that the bulk of these matters had been previously addressed and did not warrant further consideration. It therefore believed re-opening the hearing to consider the revised facilities was not necessary.

Area residents including the RRCC were unable to clearly indicate whether the hearing would be beneficial until the views of the entire membership could be obtained. The RRCC indicated this probably could not be done prior to the end of October due to harvesting and other constraints.

The Board concludes that, while many of the concerns listed in this memo of decision were considered at the original hearing, there are some new concerns arising from the amended application. These new matters respecting the amended plant and the related matter of simultaneously closing down two smaller processing plants in the general area should be addressed as well as the matters of Emergency Response Plan, emergency flaring, emergency shut-down, and potential odours from the Lo-Cat system.

Based on the above conclusions, the Board has decided to provide an opportunity for new evidence respecting the amended plant facilities and any resulting new concerns to be considered at a hearing. For that purpose the Board is arranging to re-open the hearing on 8 and 9 November 1988 at the Cardiff Community Hall. Interveners would be expected to raise any new concerns arising from Norcen's amended application dated 16 August 1988, by filing an intervention on or before 28 October 1988.

The details pertaining to the Notice of Hearing will be published shortly.

DATED at Calgary, Alberta, on 19 September 1988.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

NORCEN ENERGY RESOURCES LIMITED
APPLICATION FOR APPROVAL OF A GAS PROCESSING FACILITY IN THE CAMPBELL-NAMAO FIELD

Decision D 88-22
Application 861041

1 INTRODUCTION

1.1 Background and Application

Norcen Energy Resources Limited (Norcen) applied on 29 August 1986, pursuant to section 26 of the Oil and Gas Conservation Regulations, for approval to construct and operate a sour gas processing plant to be located in the southwest quarter of section 1, township 55, range 25, west of the 4th meridian (5-1).

The proposed gas plant was designed to process a maximum of 1583.0 thousand cubic metres per day (10^3 m^3/d) of raw gas, from which 1511 x 10^3 m^3/d of sales gas and 4.6 cubic metres per day (m^3/d) of pentanes plus (C_5+) was to be recovered. A maximum of 2.30 tonnes per day (t/d) of sulphur dioxide (SO_2)[1] was to be emitted to the atmosphere through a 16.2 metre (m) incinerator stack.

Norcen's plant proposal was opposed by area residents who formed an association known as the Rose Ridge Citizens Committee (RRCC or Committee) to carry out an independent assessment of the various concerns of its members and to ensure themselves that such concerns were satisfactorily dealt with before the proposed plant was constructed. The RRCC and Norcen entered into negotiations to resolve the residents' concerns. After holding discussions at several joint meetings, it was concluded that further negotiations would not resolve the committee's remaining concerns. Consequently, the application was considered by the Board at a public hearing in Cardiff, Alberta, on 17, 18, and 19 March 1987. Following careful consideration of all evidence presented at the hearing, the Board released its decision on 15 July 1987 approving Norcen's proposal subject to the conditions outlined in its Decision Report D 87-9.

1 Sulphur Dioxide is a compound formed during combustion from equal weights of sulphur and oxygen. Therefore, the maximum daily emission could be described as either 2.3 t/d of SO_2 or 1.15 t/d of sulphur.

Norcen subsequently met with officials from the Municipal District of Sturgeon #90 (M.D.) to discuss the rezoning of its purchased plant site property for industrial development. During these discussions Norcen learned that the M.D. was unwilling to consider the rezoning matter as they expressed concerns similar to those of the RRCC regarding the proposed plant's SO_2 emissions.

On 16 August 1988, Norcen submitted an amendment to its original application for the 5-1 gas plant, stating it would now modify the plant and install facilities for the complete removal and recovery of the sulphurous compounds contained in the raw gas entering the proposed plant.

Recognizing that the emission of SO_2 from Norcen's original proposed plant was the main issue that led to objections from area residents at the public hearing in March 1987, the Board convened a pre-hearing meeting in Campbell-Namao on 8 September 1988 and met with the RRCC and Norcen to determine if a second hearing was required to consider the amended application. It became apparent at the pre-hearing meeting that the RRCC still had remaining concerns respecting Norcen's amended application and subsequently, the Board decided to re-open the hearing to allow any new evidence to be considered.

Norcen's amended application was considered at a public hearing in Cardiff, Alberta, on 8 November 1988, with Board Member F. J. Mink, P.Eng., and Acting Board Member M. J. Bruni, sitting. Those who appeared at the hearing are listed in the attached table.

1.2 Interventions

Bankeno Resources Limited (Bankeno) and Canada Northwest Energy Limited (Canada Northwest) submitted interventions in support of Norcen's application; however, neither company participated in the hearing.

Prior to the re-opening of the hearing, the RRCC advised the Board by letter that, following the Board's 8 September 1988 pre-hearing meeting, the committee convened a general meeting at which time its members voted overwhelmingly against the location of Norcen's proposed plant. Additionally the letter stated that the members decided that the RRCC should not prepare a brief or attend the re-opening of the hearing.

A number of area residents, some of whom are members of the RRCC, attended and participated in the hearing on their own behalf.

2 ISSUES

For this amended application, the Board considered the new issues to be:

- o fugitive odours and emissions that may occur as a result of operating the modified plant,
- o potential for noise impacts from the plant, and
- o frequency and duration of plant flaring,
- o the proposed location of the plant.

3 FUGITIVE PLANT ODOURS AND EMISSIONS

3.1 Applicant's Views

Norcen stated that its modified plant, as described in its amended application, allows for the installation of a Lo-Cat sulphur recovery unit. The unit would remove virtually all the H_2S contained in the plant's inlet gas stream, and through an oxidization process, would convert the H_2S directly to elemental sulphur thereby precluding sulphur emissions from the plant. Norcen indicated that none of the chemicals used in the Lo-Cat process have an objectionable odour. It added that the periodic trucking of the recovered sulphur product would not result in fugitive odours as the Lo-Cat process is able to completely oxidize the sour gas stream and leaves no trace amounts of H_2S in the recovered sulphur. Norcen stated that the exhaust gases from the Lo-Cat unit and sulphur storage tank would be directed to a 41.0-m vent stack for proper dispersion and to eliminate any chance for odours to be detected at ground level.

Norcen said that approval of its plant with the Lo-Cat unit would actually reduce the amount of sulphurous emissions in the overall area as construction of the 5-1 plant would result in the decommissioning of Bankeno's Morinville gas plant located at 11-15-55-25 W4M (11-15) which has approval to emit 0.26 t/d of sulphur. Norcen also said that approval of its plant may eliminate the need for the full expansion of Canada Northwest's Campbell-Namao gas plant located at 13-12-54-25 W4M (13-12), which has approval to emit a total of 0.28 t/d of sulphur.

The applicant advised that Canada Northwest is the second largest company with shut-in wells in the area. Norcen's application proposes an overall scheme for the area which would make it feasible to tie in the Norcen and Canada Northwest wells into a centrally located plant that would process the gas and recover the sulphur.

Norcen stated that such a proposal was in keeping with the residents' wishes to minimize sulphur emissions in the area. The applicant stated that if Canada Northwest's shut-in wells were tied into Canada Northwest's plant, the sour gas would be incinerated and the SO_2 emitted to the atmosphere. However, if these wells were tied into Norcen's proposed plant, the sulphur would be recovered.

The applicant stated that the construction of Norcen's modified plant, the shut down of Bankeno's plant, and the tie-in of Canada Northwest's shut-in wells could result in the reduction of approximately 0.5 t/d of currently approved sulphur emissions in the area.

Norcen said that it intended to set up a monitoring program which would include a network of static monitoring stations around the plant. Norcen also stated that it would develop and implement a communication program with interested community members prior to setting up its monitoring program. The applicant said it was important to have dialogue with the community at the outset to ensure that the residents views regarding monitoring can be incorporated into the program. The monitoring devices would identify if there were any H_2S, SO_2, or hydrocarbon vapours in the vicinity of the plant. Norcen also stated it would install H_2S detectors in the plant process buildings to detect H_2S leaks. If H_2S was detected, failsafe devices would shut down the plant to prevent undue sour gas releases to the atmosphere.

Norcen stated its Lo-Cat vent stack would be equipped with an H_2S detector to ensure that the off-gas, leaving the reactor vessel, did not contain H_2S. The detector would be designed to alert the operator at the plant (or the operator on-call during the unattended mode) if the H_2S concentration in the off-gas reached 5 parts per million (ppm). Such a concentration, when dispersed from the 41-m vent stack, would result in a maximum ground level concentration of 0.0001 ppm which is well below the odour threshold for H_2S. If the monitor detected a concentration of 16 ppm of H_2S in the off-gas (this equates to a maximum H_2S ground level concentration of 0.0003 ppm), automatic plant shut-down valves would be activated and the entire plant would be immediately shut-in so H_2S could not continue to be emitted to the atmosphere. The plant's alarm system would notify the operator of the abnormal situation.

Norcen stated that the potential for H_2S release from the plant is very low. The applicant said that if there was a maximum H_2S release at the plant, under worst case conditions, the area affected by the release would only extend about 100 m outside the plant site boundary. This area is considered to be the evacuation zone. Norcen said that although its proposed plant would be situated on a 5-acre (2.0 hectares (ha)) parcel, it had purchased 80 acres (32 ha). This would ensure that the 100 m evacuation zone around the processing facilities would be confined

within Norcen's property. Norcen added that the nearest resident Mr. W. Blach, lives more than 400 m to the southeast of the plant site and would be well outside the evacuation zone. Norcen also added that it could not envision any situation which would ever endanger any of the area residents and at no time would they have to be evacuated. Norcen said that the regulations do not require gas plants with such a localized hazardous zone to develop an emergency response plan. However, Norcen stated that if area residents requested an emergency response plan, it would work with the interested residents and jointly formulate a response plan.

3.2 Interveners' Views

W. Blach stated that if the gas processing facilities were constructed at the 5-1 site, he would live closest to the plant, and questioned Norcen whether he would be put at risk at his residence. He asked whether he would have to be evacuated from his home if there was a northwest wind during a worst-case H_2S release at Norcen's plant. He also questioned Norcen's claim that the plant would not be a source of detectable odours. W. Blach said he visited the Hewitt Oil (Alberta) Ltd. plant in the Golden Spike Field, which also utilizes the Lo-Cat process and during his visit he claimed he detected odours on the plant site.

Mr. A. Sinkovics, who has a honey bee operation immediately to the east of the Blach residence, shared similar concerns as W. Blach. A. Sinkovics said that regardless of Norcen's assurances about the processing facility's proper design, he maintained the plant would emit undesirable odours.

Mr. G. MacKay, whose residence is 4.0 km south of Norcen's 5-1 plant site, said that on one occasion he was impacted by odours emanating from Canada Northwest's 13-12 plant which is in the vicinity of his residence. He therefore claimed he could understand why the residents nearest the 5-1 site were skeptical about Norcen's proposed plant.

Mr. B. Bocock, who indicated his residence is some 3.0 km west southwest of the 5-1 plant site, said he was concerned about the sulphur that would be emitted to the atmosphere when the plant would have to flare during abnormal conditions.

Mr. C. Crozier stated that he had concerns about Norcen's original application; however, with the addition of the proposed sulphur recovery facilities, he personally was no longer opposed to Norcen's gas plant. He stated there is a need to establish a means of properly addressing residents' concerns including odour complaints. He further stated he would actively participate in a committee initiated by Norcen to interface with residents and apprise them of plant operations, and to identify and alleviate their concerns.

3.3 Board's Views

The Board believes that the operating history of the existing Lo-Cat units in the province has demonstrated that the technology is a reliable means of removing and recovering the levels of sulphur that would be contained in the Norcen plant's acid gas stream. The Board also notes that approval of the modified plant would permit recovery of some of the sulphur that is presently being emitted to the atmosphere from approved acid gas flaring plants in the area. In total, the Board is satisfied that Norcen's proposed facility would reduce the environmental impact of sulphur emissions in the area.

The Board notes that Norcen proposes to utilize a 41.0-m vent stack to discharge the H_2S free carbon dioxide, and excess oxidizer-air off-gas from the absorber/oxidizer vessel, to the atmosphere rather than vent that stream from the top of the reactor vessel as is the usual practice with Lo-Cat units. The Board believes that Norcen's provision should ensure there are no detectable odours from the plant's processing facilities.

Norcen would direct all of its produced liquid hydrocarbons to a pressurized LPG storage tank. Given that no atmospheric storage of liquids would occur at this site, the Board believes that this should prevent fugitive emissions from Norcen's plant.

The Board recognizes Norcen's commitment to fully implement an environmental monitoring program and to investigate all complaints and communicate the results to the complainant within a 24-hour period. The Board believes that such a program, in addition to ongoing dialogue with the community members on plant operations, should ensure that odours are minimized or eliminated to the greatest practical extent.

The Board believes that Norcen's commitment to establish a communications committee with interested parties, to jointly review all the previously imposed conditions and to obtain input from the residents, is constructive. The Board expects that following the joint discussions, Norcen would implement all the mutually agreed-to conditions.

While the Board does not expect the proposed plant to present a danger to nearby residents, it notes Norcen's willingness to formulate a response plan if the nearby residents request that a plan be established.

Given that virtually all sulphur would be recovered at the facility during normal operations, the Board believes the proposed facility would reduce the cumulative sulphur loading in the area and offer an improvement to the existing environment.

4 NOISE IMPACTS

4.1 Applicant's Views

Norcen stated its modified plant would comply with the Board's recently issued Noise Control Directive, Interim Directive ID 88-1. Norcen advised that its main gas driven compressors, which have been operating at other Norcen facilities, would be fully reconditioned and each would be equipped with a hospital-type exhaust silencer to ensure there would be no plant noise impact at the nearest occupied dwelling adjacent to the plant.

4.2 Interveners' Views

Mr. N. Taylor asked what the current noise control requirements were and questioned whether Norcen's plant could comply with the noise directive, given Norcen's plan to utilize used compressors at the 5-1 site.

4.3 Board's Views

The Board's Noise Control Directive ID 88-1 was issued in October 1988 and came into effect immediately. The applicant is compelled and the plant is designed to comply with the new noise control requirements. Therefore, the Board believes that plant noise would not create an impact on the area residents.

5 FREQUENCY AND DURATION OF PLANT FLARING

5.1 Applicant's Views

Norcen stated that emergency plant flaring would be very infrequent. Flaring would only occur if the fire detection devices, which would be situated in each of the process buildings, detected a flame, or if there was a major electrical equipment malfunction, or if a major plant upset occurred requiring the plant vessels to be depressured to the 41.0-m emergency flare stack. The flare stack would be equipped with a continuously lit flare pilot and an automatic flare pilot ignitor to ensure that the H_2S in the raw gas, sent to flare during emergencies, would be completely combusted and converted to SO_2. Norcen added that during normal operating conditions the continuous pilot flame would be partly concealed by the shroud on the top of the stack which would be installed to prevent the wind from extinguishing the flame.

The applicant said that during emergency flaring situations the flare would be visible for 3 to 5 minutes while all the gas within the plant's piping and vessels is diverted to the stack and burned.

The applicant said that the plant would incorporate an operator call-out system when the plant is in an unattended mode to alert the operator if an abnormal situation develops. Norcen stated that in such situations its operators would be able to arrive at the plant site in approximately 30 minutes to carry out corrective measures.

Norcen said that the plant was designed to operate safely and to ensure compliance with current regulations which specify that the total plant flaring cannot exceed 0.5 per cent of the plant's total annual raw gas inlet. It emphasized that an emergency flaring situation would not jeapardize any of the area residents as under upset conditions the maximum one hour ground level concentration of SO_2 would be 0.034 ppm, well below the province's hourly air quality objective of 0.17 ppm.

5.2 Interveners' Views

N. Taylor questioned whether there would be a visual impact from the flare stack's continuously lit pilot. B. Bocock said he understood that during an emergency flaring situation, the plant could flare continuously for up to 6 hours and therefore he was concerned that such emergency flaring could result in the emission of sulphur which he claimed would cause corrosion of farm machinery and barbed wire.

5.3 Board's Views

The Board believes that Norcen's modified plant would be equipped with appropriate flare facilities, operator call-out system, and plant shut-down devices to ensure that emergency plant flaring is minimized to the greatest extent possible. The Board notes that the plant is properly designed and accepts the applicant's position that Norcen will operate the plant prudently and will ensure compliance with the province-wide gas plant flare allowance.

6 PROPOSED LOCATION OF THE PLANT

6.1 Applicant's Views

Norcen said its proposed 5-1 plant location is the optimum site as it is centrally located, will require minimum pipeline tie-ins for sour gas production from wells in the area, and is also located in close proximity to Norcen's existing gas gathering systems. Norcen stated that its plant had to be located where the existing pipelines are and therefore it could not relocate its plant to the M.D.'s heavy industrial area which is located north of Fort Saskatchewan.

The applicant stated that during the summer of 1988 Norcen and the RRCC entered into a mediation process during which time the matter of the proposed plant location was examined. However, Norcen said that during the mediation no other mutually acceptable and viable alternative plant site was identified.

Norcen stated that if its processing facility was constructed at 5-1, the plant site would occupy 5 acres (2 ha) of what is presently agricultural land. The applicant said that although it has acquired an 80-acre (32 ha) parcel on the southwest quarter of section one, it had applied to re-zone only 10 acres (4 ha), in the centre for industrial use. The applicant added that the remaining land would serve as a buffer and would separate the two surface land uses; however, the buffer zone would continue to be farmed.

Norcen reiterated that approval of its application would result in the decommissioning of Bankeno's 11-15 Morinville plant, and advance the shut-down of Norcen's Campbell-Namao gas plant in SE 1/4-26-54-25 W4M (Campbell-Namao plant). In total this would result in 9 acres (3.6 ha) of land being returned back to its original condition as reclamation of the plant sites would be conducted in accordance with all government requirements and regulations. Norcen stated that although the new plant would take 5 acres (2 ha) of land out of agricultural use there would be an overall net return of 4 acres (1.6 ha) which would be returned to its original use with the decommissioning of the two existing plants in the area.

6.2 Interveners' Views

W. Blach stated he opposed the construction of Norcen's plant in the applied-for 5-1 site as the plant would be situated some 400 m west-northwest of his residence. He stated he would favour the M.D. establishing an industrial park further away from residences in the area, adding that if Norcen's plant was constructed in such an area designated for industrial development, he would find Norcen's scheme acceptable. He also stated that future industrial development in such a designated area would not likely meet with public opposition.

G. MacKay raised similar concerns as W. Blach, and questioned why Norcen's plant could not be situated in an area that has already been zoned for industrial use.

B. Bocock said that rezoning Norcen's applied-for plant site from agricultural to industrial use would set a precedent and would be contrary to orderly development. He claimed that although 10 acres (4 ha) of Norcen's parcel would be rezoned initially, he questioned whether Norcen would risk locking itself into zero growth and no expansion.

A. Sinkovics read into the record a letter from R. Mcleod who has an interest in Mr. Sinkovic's property in the area. R. Mcleod's letter indicated he was concerned that Norcen's plant would take arable land out of production. It claimed that Norcen's proposal would deprive the surrounding landowners of the full enjoyment of their property and may lower land values in the area. No alternative location was proposed by R. Mcleod.

C. Crozier stated that, over the years, the M.D. has found that there is not a perfect location for any proposed development. Historically, resource extraction facilities have been constructed where the resources are located, and the county would consider this a factor in making its decisions. He stated that with Norcen's zero emission modified plant, and having regard for all of the other undertakings that have been committed to, including maximizing plant aesthetics, the county may consider rezoning the applied-for site for such a plant.

6.3 Board's Views

The Board notes that although the RRCC's intervention, dated 28 October 1988, stated that its membership had overwhelmingly voted against Norcen's proposed location, no alternative plant sites were suggested. The Board recognizes the public's concern with the operation of sour gas processing facilities in a populated area; however, the guidelines and conditions imposed on gas processing plant operators and the commitments made by the applicant should reduce the environmental impact to negligible levels. The Board believes that a remote location for processing the existing gas resources would likely result in greater land use impacts than that required by the existing application. Therefore, the Board concludes that Norcen's proposed location would be appropriate for processing the area's gas reserves.

7 DECISION

The Board has carefully considered all the new evidence, including the concerns expressed by the interveners and the information supplied by the applicant. Although the Board recognizes that some outstanding concerns exist for local interveners, it is satisfied that the proposed plant would meet or exceed all regulations and requirements that are established to ensure public safety and environment protection.

Additionally, the Board recognizes Norcen's commitment to enhance aesthetics and minimize the visual effect of the plant. Therefore, subject to receipt of the required approval of the Minister of the Environment with respect to environmental matters, the Board is prepared to issue an approval to Norcen for the construction and operation of the plant as modified in its application.

DATED at Calgary, Alberta on 19 January 1989.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng
Board Member

M. J. Bruni
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Norcen Energy Resources Limited (Norcen) D. G. Davies	J. G. Schopp, P.Eng. R. Bergevin, P.Eng. both of Norcen Energy Resources Limited
A Group of Area Residents W. Blach Jennifer Bocok G. MacKay A. Sinkovics	B. Bocock A. Sinkovics
Councillor in the Municipal District of Sturgeon #90 (M.D.) C. Crozier	C. Crozier
MLA For Constitutuency of Westlock-Sturgeon N. Taylor, P.Eng.	
Alberta Environment Staff W. Diepeveen	
Energy Resources Conservation Board staff C.J.C. Page M. Semchuck, C.E.T. M. T. Pittman	

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

UNIVERSAL EXPLORATIONS LTD.
GAS PROCESSING PLANT — Decision D 88-23
HUSSAR, WINTERING HILLS, AND SEIU LAKE FIELDS — Application 870772

1 INTRODUCTION

Czar Resources Ltd. (Czar) operates a gas plant located at legal subdivision 6 of section 33, township 23, range 18, west of the 4th meridian (6-33 site). The unit commenced operations in 1978 and has approval to process up to 316 thousand cubic metres per day (10^3 m^3/d) of raw gas. In 1983 Czar began processing gas for Universal Explorations Ltd. (Universal) on a custom processing fee basis. Universal's portion of the gas currently processed in the Czar plant is approximately 50 per cent of the current daily plant throughput.

2 APPLICATION AND HEARING

Universal applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct and operate a new facility to process its portion of the gas currently tied into the Czar gas plant. The proposed new gas processing equipment would be situated at an existing compressor station site located at Lsd 11-36-23-18 W4M (11-36 site). The facility would be designed to process a maximum of 114 x 10^3 m^3/d of raw associated and non-associated gas from which 111 x 10^3 m^3/d of sales gas and 7.0 m^3/d of liquefied petroleum gases (LPG mix) would be recovered.

Czar intervened on the basis that the proposed plant would duplicate the existing gas plant which has been processing Universal's gas for about 5 years.

A public hearing to consider Universal's application was held in Calgary, Alberta, on 2 February 1988, with N. A. Strom, P.Eng., J. P. Prince, Ph.D., and E. J. Morin, P.Eng., sitting.

Those who appeared at the hearing are listed below.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Universal Explorations Ltd. (Universal) D. Buchanan	D. A. Mercier, P.Eng. D. R. Seidlitz, P.Eng. (Seidlitz Engineering Ltd.)
Czar Resources Ltd. (Czar) J. K. Farries	R. Ewacha, P.Eng. G. F. Elliot, C.E.T. J. K. Farries, P.Eng. (Farries Engineering (1977) Ltd.) K. Foore P. W. Payzant, P.Eng.
Energy Resources Conservation Board staff A. Broughton G. Habib E. P. Moeller, R.E.T. S. A. Brockhoff	

No other interveners or participants appeared at the hearing.

3 OTHER MATTERS

3.1 Reasons for Delaying Issuance of the Decision

The Board was aware that prior to the hearing Universal and Czar were involved in negotiations intended to lead to a business arrangement that would allow for the continued processing of Universal's gas in the Czar plant, and eliminate the need for a new Universal plant. During the hearing, both Czar and Universal agreed that further negotiation was possible and agreed that they would continue to seek resolution. The Board saw merit in having both parties negotiate a mutually acceptable private agreement rather than imposing a Board decision on such a potential arrangement.

During the ensuing months and into early October, the Board understood from the parties that negotiations were continuing and that there was progress toward an agreement. By a letter to the parties dated 5 October 1988, the Board sought confirmation that a negotiated settlement had been achieved. Universal replied on 17 October 1988, indicating that no agreement had been reached and Czar replied on 7 November 1988, advising that, from its perspective, a negotiated settlement had been reached between itself and Universal. Universal replied on 17 November 1988, reiterating that no agreement was in place and further requesting that the Board issue its decision on this

application. Czar responded in a letter dated 6 December 1988 requesting that the hearing be reopened. Universal again replied by letter dated 14 December 1988 that no further evidence would result from reopening the hearing and again requested that the Board rule on its application. Subsequently in verbal communication, Czar acknowledged that there would be little to gain from reopening the hearing and withdrew its request. The Board concluded that a negotiated solution was no longer possible, and therefore resumed consideration of the evidence filed at the time the application was heard.

4 ISSUES AND CONCERNS

The main concerns relate to the economic and technical merits of alternative processing arrangements, the right of gas producers to develop competing schemes, and the potential impact of duplication of facilities on resource conservation. The Board considers the issues to be

- required gas plant capacity,
- conservation of gas and natural gas liquids, and
- general effects of plant proliferation.

5 REQUIRED GAS PLANT CAPACITY

5.1 Views of the Applicant

Universal stated that its proposed plant would be located on an existing production battery site which has sufficient space to accommodate the required processing equipment. The applicant said that it would have to replace the existing field compressor with a larger unit and replace the existing dehydration building with a skid-mounted processing facility. Universal contended that the Czar gas plant has insufficient processing capacity to accommodate the combined gas production from Universal and Czar and other owners' wells, especially on peak gas contract demand days. The applicant stated that Hussar and other fields in the vicinity are one of the few areas not restricted in access to firm gas contracts. Universal said that Czar had reserved 250.7 x 10^3 m^3/d of capacity for itself from its plant which is approved to process up to a maximum of 316 x 10^3 m^3/d of raw gas. Meanwhile, Universal needed 112.7 x 10^3 m^3/d of plant capacity on a guaranteed basis. The difference between design capacity and reserved requirements leaves Universal with only 65.3 x 10^3 m^3/d of guaranteed capacity. The applicant therefore concluded that additional processing equipment was required in the area. Universal stated that it is not economic to install the additional capacity that is needed to meet its requirements at the Czar plant. It concluded that its best option would be a small, operator-owned and operated plant of the type it has applied for.

5.2 Views of the Intervener

Czar agreed that its plant is approved for 316 x 10^3 m^3/d of gas but said that the facility is physically designed to process up to 371.9 x 10^3 m^3/d of gas. The intervener also said that its peak day gas contract demand load of 250.7 x 10^3 m^3/d is based on a once per year deliverability test arrangement with Czar's gas purchaser. It agreed with Universal that peak day demand loads on the plant could be a limiting factor on the facility; however, Czar said it was unlikely that both Universal and Czar could receive peak gas demands at the same time. Czar said it was therefore prepared to guarantee Universal 112.7 x 10^3 m^3/d of process capacity, and to install upgraded liquids recovery facilities on a cost-share basis calculated on the percentage of plant ownership. It considered the economics of the Universal scheme, for a new plant, to be relatively less attractive. Czar also stated that operating costs and processing fees charged to remaining plant owners would likely rise if Universal's gas is withdrawn from the Hussar plant. Czar expressed a concern that turndown rates at the existing plant would be reached prematurely and would also have a negative effect on plant efficiency.

5.3 Views of the Board

The Board agrees with both the applicant and the intervener that there is some deficiency of plant capacity to meet peak-day demands. Greater capacity can be developed through expansion of the older Czar plant or by the addition of a smaller plant in the region. The appropriate choice must take account of both commercial and public interests.

6 CONSERVATION OF GAS AND NATURAL GAS LIQUIDS

6.1 Views of the Applicant

Universal stated that its plant would result in overall improved gas and natural gas liquids conservation. It said that during the last 2 years it had sought a working interest in the Czar facilities so that it could exercise some degree of direct control over the operation. Universal wanted to see the Czar plant upgraded to improve plant capacity and provide enhanced liquids recovery, but said it met with little success in its negotiations with Czar. Universal pointed out that the present Czar plant at Hussar is essentially a dew-point control facility, only capable of recovering a pentanes-plus product. The applicant said that its proposed plant would include refrigeration facilities to -35°F capable of recovering propane and butanes as well as pentanes-plus.

6.2 Views of the Intervener

Czar countered Universal's concerns by stating that it is willing to sell the applicant one third ownership in its plant and additionally offered to install upgraded liquids recovery facilities comparable to

the level of efficiency proposed by Universal. Czar also stated that, while it is prepared to negotiate with Universal on matters such as conservation levels and ownership, it was not prepared to give up operatorship of the plant.

Czar said that liquids recovery upgrading would be feasible only if Universal's gas remained in its plant. Czar saw little prospect of further gas developments in the general area. Therefore, if Universal's gas were withdrawn from the Czar plant, processing costs per unit for the remaining gas would increase. These increased costs would have to be borne by the producing wells, the result being earlier abandonment and loss of raw gas reserves.

6.3 Views of the Board

Since gas liquids are recovered at straddle plants, field recovery, although it might be marginally more efficient, would not contribute significantly to overall conservation of gas liquids.

Universal's desire to benefit from recovery of the liquids in its produced gas stream is legitimate; however, the Board notes Czar's expressed willingness to upgrade its facilities for recovery of liquids. In any case, the incremental volume of gas liquids that would be recovered from the gas produced by Universal is relatively small. For these reasons, the potential conservation of gas liquids is not considered by the Board in this case to be a dominant factor in deciding this application.

Conservation of natural gas could be adversely affected if Universal's gas were removed from the Czar plant. Removal of Universal's gas would increase the average costs of processing the remaining gas unless either total costs could be reduced proportionately or new sources of gas could be found to replace Universal's gas. Higher average costs would translate to higher processing fees, potentially resulting in premature abandonment as the remaining gas resources become uneconomic at an earlier stage of production.

Although the Board believes that the above argument is directionally correct, assessing the outcome is difficult in any specific case. In the case at hand, there was disagreement about the potential for developing new reserves in the region. Neither party provided evidence that would allow the Board to form an opinion of that potential. Similarly, no evidence was provided on the extent to which a reconfiguration of the Czar plant would allow a reduction in the total costs of processing the smaller volume of gas. Consequently, the Board is unable to determine whether an increase in costs would follow from diversion of Universal's gas or, in the event that costs did increase, whether that increase would be enough to reduce significantly the volume of gas eventually recovered.

The Board notes that other producers using Czar's plant did not intervene to express concerns about removal of Universal's gas from the

Czar plant. The inference the Board draws is that reduced throughput at the Czar plant would not translate into burdensome processor costs.

7 PROLIFERATION OF GAS PLANTS AND THEIR IMPACT

7.1 Views of the Applicant

Regarding proliferation of facilities, Universal said that its proposal would have little or no impact on the environment because of the type and location of the gas processing equipment it is proposing. Additionally, Universal said that approval of its plant would have no effect on Crown royalty nor would the new plant result in higher deductions under the gas cost allowance provision, because Universal's gas is produced from freehold leases. The applicant acknowledged that, although approval of its plant would allow it to control its own operating costs, it is proper for the Board to consider the matter of plant proliferation in relation to the environmental impacts and the overall public benefit.

7.2 Views of the Intervener

Czar stated that the Board should assess the need for a plant on the basis of broad economics and public interest whenever there is impact on the public and owners of energy resources and energy developments in an area. In this case Czar said the Board should evaluate the impact that would result from the under-utilization of its plant if the proposed facility is built. The intervener said that it does not share Universal's optimism for development of additional gas reserves in the area and reiterated that it is willing to work toward finding a suitable arrangement with Universal to participate in the existing Czar plant.

7.3 Views of the Board

The Board is aware that in the past 5 years the number of gas plants in the province has increased significantly while overall utilization of plant capacity remains at about 45 per cent of approved throughput. Some excess processing capacity may be justified; but with capacity approximately double what is needed, even on days of peak throughput in the system, the Board must consider strengthening the criteria to assess applications that may result in redundant processing plant capacity. Currently, in assessing the potential impact of new plants, the Board considers the likely effect of the plant on the surrounding environment as well as a more general question of whether or not the addition of a plant would contribute to the economic, orderly, and efficient development of the province's resources.

In the case at hand, the effect on the environment would be small since the facilities would be located at an existing compressor station site, and since the existing dehydration unit would be replaced with a skid-mounted processing facility that could be removed easily at some later time.

The question of economic, orderly, and efficient development is less easily judged. The application could be declined if a significant adverse effect on conservation were apparent, since that would clearly imply that the proposal would be uneconomic from the viewpoint of the province. But from the inferential conclusion in section 6.3, that is not the case here. So the question appears to hinge on a comparison of two cases: expansion of an older, less efficient plant versus the construction of a small, and somewhat more technically efficient, new plant.

Although the Board had hoped the two parties would negotiate a solution to this question, the choice between expanding the old plant and building a new plant cannot necessarily be decided on commercial grounds alone. Had the parties agreed to an expansion of the old plant, the Board would have accepted that as being in the public interest because there are no potential conflicts between public and private interests, if that option is chosen. The absence of an agreement on that option does not imply that the addition of a new plant is in the public interest. The reasons for an agreement not being reached between two parties may include things that enhance the private interest of one party or the other while adversely affecting the legitimate interests of the public.

Therefore, in the absence of a negotiated agreement, the Board is forced to consider whether or not adding a new plant can be judged "economic, orderly, and efficient" in the public interest. The evidence provided at the hearing does not allow an unequivocal answer to that question. However, the Board's view is that sufficient evidence was heard to conclude that, if it turned out that a new plant was not in the public interest, the adverse effect on the public would be relatively small.

8 FINDINGS

The Board finds that the need for enhanced facilities to recover liquids has been demonstrated. These facilities could be part of a new plant situated at an existing compressor station site at 11-36. They could also be added to the Czar Resources Hussar gas plant if suitable terms could be negotiated. Additionally, the Board would have accepted a negotiated settlement to expand the Czar plant because it would reduce the possibility of gas recovery in the region being adversely affected by increased unit costs at that plant. It would also avoid partially duplicating facilities and thus minimize any potential impact on the environment, and it would have no apparent adverse effect on the public interest.

In the absence of a negotiated settlement, the Board must consider that development of reserves in the vicinity may justify two facilities in future and the possible adverse economic effects from a new plant, although hard to quantify, appear relatively small in this case.

Having weighed the evidence, the Board has decided to grant Universal's application and will insert a lapse clause in the permit to terminate the approval if construction has not commenced within 1 year of the date of this decision.

9 DECISION

The Board hereby approves Application 870772 subject to the concurrence of the Minister of the Environment with respect to environmental matters and subject to the further condition that should construction of the Universal plant not proceed within 12 months of this date, the approval for the plant shall be rescinded.

DATED at Calgary, Alberta, on 12 January 1989.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

J. P. Prince, Ph.D.
Board Member

E. J. Morin, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

PLANNING MEETING ON ETHANE POLICY IMPLEMENTATION

MEMORANDUM OF DECISION
PROCEEDING 871318

1 INTRODUCTION

Concurrently with the Government of Alberta issuing a Policy Statement on Ethane on 21 August 1987, the Minister of Energy, the Honourable Dr. Neil Webber, requested that "the ERCB consider and report on the ethane policy, with particular reference to" certain specific matters which have been repeated in section 3 of this Memorandum of Decision.

In order to determine the most effective way to proceed to satisfy the Minister's request in a timely manner, the Board held a planning meeting with interested persons on 1 September 1987 with G. J. DeSorcy, P.Eng., N. A. Strom, P.Eng., and J. P. Prince, Ph.D., sitting.

The attached table lists the meeting participants.

2 NEED FOR A PUBLIC INQUIRY

There was strong support by most participants for a public hearing process to inquire into the matters requested by the government. There was also agreement by participants to a proposed inquiry schedule submitted by Dow Chemical Canada Inc. including a hearing date of 26 October 1987. The Board accepts Dow's proposed schedule and sets the matter down for hearing at the offices of the Board in Calgary commencing on 26 October 1987. Notice is being published in the major Alberta newspapers and is being distributed to interested parties.

Filing dates for submissions and subsequent information will be in accordance with the schedule suggested at the meeting and attached hereto. The second step of the schedule, "Information Requests", provides for inquiry participants to request additional information to be provided by those that have filed submissions. The responses to these requests form the third step of the schedule. Because these deadlines are tight, the Board asks for the cooperation of all parties in providing any additional information requested to the best of their ability within the scheduled deadline. The last step provides for filing direct evidence and evidence respecting other participants' submissions, as well as the usual information respecting panel witnesses, etc. This step is intended to assist in conducting the hearing in the most effective and expeditious manner.

3 TERMS OF REFERENCE

All participants requested the Board to clearly define the scope of the inquiry and to do so as quickly as possible.

The Minister's letter requested that "the ERCB consider and report on the ethane policy, with particular reference to the following specific matters:

1. The determination of the ethane facilities which should be affected by or be part of this policy.

2. The principles that should be used in determining the threshold volumes and the actual volumes thereby determined.

3. The determination of the procedures for requiring and the mechanism for ensuring re-injection or supply of ethane to the straddle plant system.

4. Procedures that should be used for the expedient regulatory processing of applications for field ethane extraction facilities.

5. The existing and potential efficiency of ethane extraction at the straddle plants, the investment required to enhance extraction, and potential linkages with threshold volumes.

6. Any legislative changes required to implement the policy.

7. Any other relevant matters."

Although there were some requests for allowing the widest possible opportunity to speak to the policy itself, in the Board's interpretation, the Minister's request is not for a detailed review of the ethane policy and alternatives to it, but rather to have the Board focus on specific aspects pertaining to implementation as set out in his letter and listed above. Therefore, the Board intends to limit the scope of the inquiry to these specific matters and any other relevant matters respecting implementation. In the course of doing so, it will accept consideration of the policy to the extent that it bears on the practical matters of policy implementation as listed by the Minister.

Additionally, with respect to certain other matters raised at the planning meeting including questions concerning enhanced oil recovery, ethane royalty, and proprietary rights of operators, the Board will deal with these to the degree that they relate to the specific matters identified in the Minister's letter.

ISSUED at Calgary, Alberta, on 8 September 1987.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, concurs with the contents,
and with the issuance of this report.

G. J. DeSorcy, P.Eng.
Chairman

N. A. Strom, P.Eng.
Vice Chairman

J. P. Prince, Ph.D.
Board Member

INQUIRY SCHEDULE

Step		Deadline Date
1	Filing of Submissions	28 September 1987
2	Information Requests	5 October 1987
3	Responses to Information Requests	12 October 1987
4	Filing of Direct Evidence	19 October 1987
5	Inquiry	26 October 1987

THOSE WHO APPEARED AT THE MEETING

Principals	Representatives
Alberta Gas Ethylene Company Ltd.	H. D. Williamson
Alberta Natural Gas Company Ltd and Alberta and Southern Gas Co. Ltd.	M. A. Putnam, Q.C.
Amerada Minerals Corporation of Canada Ltd.	M. A. Meghani, P.Eng.
Amoco Canada Petroleum Company Ltd.	R. W. Mustard, P.Eng.
Anderson Exploration Ltd.	A. H. Williamson, P.Eng.
Canadian Hunter Exploration Ltd.	R. T. Booth
CanStates Energy	C. J. Robb
Chevron Canada Resources Limited	R. A. Pashelka
Conoco Canada Limited	D. Dachis
Dome Petroleum Limited	A. L. McLarty
Dow Chemical Canada Inc.	R. A. Neufeld
Esso Resources Canada Limited	D. J. Henry
Gulf Canada Resources Limited	J. T. Caffrey, P.Eng.
Home Oil Company Limited	H. L. Hooker
PanCanadian Petroleum Limited	P. R. Murray
Petro-Canada Inc.	W. J. Hope-Ross
Shell Canada Limited	R. W. Riegert
Sulpetro Ltd.	R. R. Lane
Texaco Canada Resources	W. Muscoby
Energy Resources Conservation Board staff	M. J. Bruni J. D. Dilay, P.Eng.

ERCB

Alberta Ethane Policy

Report on Implementation

April 1988

ERCB

Alberta Ethane Policy

Report on Implementation

REPORT TO THE MINISTER OF ENERGY WITH RESPECT TO AN INQUIRY HELD TO CONSULT WITH THE INDUSTRY ON THE GOVERNMENT OF ALBERTA'S ETHANE POLICY AND REPORT ON ITS IMPLEMENTATION

April 1988

ALBERTA ETHANE POLICY
REPORT ON IMPLEMENTATION

Report D 88-D published April 1988

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ABBREVIATIONS AND ACRONYMS USED IN THIS REPORT

10^3	one thousand
10^6	one million
AGE I & II	Alberta Gas Ethylene's First & Second Ethylene Plants
AGE III	Alberta Gas Ethylene's Proposed Third Ethylene Plant
AEGS	Alberta Ethane Gathering System
AGEC	Alberta Gas Ethylene Company Ltd.
Amoco	Amoco Canada Petroleum Company Ltd.
Anderson	Anderson Exploration Ltd.
ANG	Alberta Natural Gas Company Ltd
Board or ERCB	Energy Resources Conservation Board
bbl/d	barrels per day
Btu	British thermal unit
Canterra	Canterra Energy Ltd.
Cdn. Hunter	Canadian Hunter Exploration Ltd.
Celanese	Celanese Canada Inc.
CEMJV	Cochin Ethane Marketing Joint Venture
Chevron	Chevron Canada Resources Limited
C-I-L	C-I-L Inc.
Conoco	Conoco Canada Limited
Dome	Dome Petroleum Limited
Dow	Dow Chemical Canada Inc.
EDI	Ethylene Derivative Industry
EGLJV	Empress Gas Liquids Joint Venture
EOG	Ethane Owners Group
EOR	Enhanced Oil Recovery
Esso	Esso Resources Canada Limited
Gulf	Gulf Canada Resources Limited
Home	Home Oil Company Limited
IPAC	Independent Petroleum Association of Canada
m^3	cubic metres
m^3/d	cubic metres per day
Mobil	Mobil Oil Canada, Ltd.
NGL	natural gas liquids
NOVA	NOVA, An Alberta Corporation
Novacor	Novacor Chemicals Ltd.
Norcen	Norcen Energy Resources Limited
PanCanadian	PanCanadian Petroleum Limited
Petro-Canada	Petro-Canada Inc.
Poco	Poco Petroleums Ltd.
Project	Alberta Ethane/Ethylene Petrochemical Project
Shell	Shell Canada Limited
SPO	Straddle Plant Owners
Sulpetro	Sulpetro Limited (now owned by Esso)
Texaco	Texaco Canada Resources
Union Carbide	Union Carbide Ethylene Oxide/Glycol Company

DEFINITIONS USED IN THIS REPORT

BTU VALUE	Heat value of a product measured for its energy content.
CYCLING	A method for producing a liquid-rich retrograde reservoir so as to maximize hydrocarbon recovery. The produced gas is processed to remove the natural gas liquids and the residue gas is reinjected into the reservoir to maintain the reservoir pressure.
DEBOTTLENECK	A term used for referring to improvements in production capability of a plant through fine tuning of components or piping.
DEEP-CUT	A term which refers to a plant which extracts ethane and heavier hydrocarbons from natural gas streams.
DOWLING LETTERS	Letters dated 17 and 19 September 1975 and 26 April and 11 May 1976 between The Honourable R. W. Dowling, then Minister of Business Development and Tourism, and the proponents of the Alberta Ethane/Ethylene Petrochemical Project (Dow, Dome, AGEC, and The Alberta Gas Trunk Line Company Limited, now NOVA).
DOWNSTREAM	A term referring to facilities which process or use gas and which are located on pipelines transporting gas to markets.
DOWNSTREAM PARTICIPANTS	The downstream participants at this inquiry included AGEC, ANG, CEMJV, EDI, and SPO.
ENHANCED OIL RECOVERY	Any method for enhancing oil recovery from a pool over what would be obtained through natural depletion (gas cap expansion, natural water influx, and solution gas drive).
ETHANE-PLUS	Mixture of natural gas liquids consisting of ethane and heavier hydrocarbons.
ETHANE-RICH	A term which refers to a gas stream or reserves containing a high concentration of ethane.
FIELD PLANT	A plant near the source of gas, which processes raw gas and is located upstream of pipelines which move the gas to markets. Some of these extract ethane.

FUEL VALUE	Value of a product based on its use as a fuel.
MISCIBLE FLOODS	A method for enhancing oil recovery where the reservoir is flooded with a miscible solvent, often natural gas liquids. The major part of the solvent will be reproduced over the remaining life of the pool.
NATURAL GAS LIQUIDS	A term referring to the heavier components recovered from processing natural gas. It generally includes propane, butanes, pentanes, and heavier hydrocarbons.
PLANCHE LETTERS	Letters dated 16 and 30 December 1985 between The Honourable H. L. Planche, then Minister of Economic Development, and the proponents of the Project.
POLICY STATEMENT	Alberta Government Policy on Ethane dated and released on 21 August 1987.
PURE ETHANE	Ethane which does not contain any natural gas liquids or other impurities.
SHRINKAGE COST (ETHANE)	Calculated value of ethane based on the natural gas equivalent of its energy content.
SPECIFICATION ETHANE	Ethane that is typically processed by Alberta petrochemical plants into ethylene. It contains approximately 94 per cent pure ethane.
STRADDLE PLANT	A reprocessing plant located on a pipeline. It extracts natural gas liquids from previously processed gas before such gas leaves or is consumed within the province.
TORONTO CITY GATE	A term previously used as a reference point for pricing oil and gas. Prices at this point do not include local distribution charges but include transportation costs to Toronto.
THRESHOLD VOLUME	A volume of ethane referred to in the Alberta Government Ethane Policy. It is to be made available to the straddle plant system for use by the Project. If measured at the inlet of the straddle system it is called the threshold inlet volume; if measured at the outlet of the straddle plant system it is referred to as the threshold output volume.
UPSTREAM	A term often used to refer to processing facilities located at the field near the source of the produced gas.

EXECUTIVE SUMMARY

An ethane policy was developed by the Government of Alberta in an effort to resolve an ongoing dispute between the gas producing industry and the Alberta Ethane/Ethylene Petrochemical Project (the Project). This world-scale project upgrades ethane from a component of natural gas typically consumed for its energy value to ethylene and ethylene derivatives.

The dispute is centred around the ownership of, or at least the right to extract ethane from, the gas produced in Alberta. The Project obtains its ethane feedstock largely from straddle plants, located on main gas transmission pipelines, that extract ethane and other hydrocarbon liquids before the gas is exported from the province or is used within the province. Much of the gas processed at the straddle plants has already been processed upstream at plants located in or near the gas fields to recover propane, butanes, and pentanes-plus.

Until recently, very little ethane was extracted at the field plants. But since the early 1980s, another demand for ethane in the province has created interest among gas producers in recovering ethane at field plants. This demand is for ethane to make up part of the solvent that is injected into oil reservoirs to increase oil recovery.

Since 1982, the ERCB has granted a number of approvals to extract ethane at field plants where the raw gas is comparatively ethane-rich. Almost every such application has been opposed by the Project on the basis that extraction in the field reduces the concentration of the ethane in the export gas available at the straddle plants and thereby increases the cost of the ethane that is extracted at the straddle plants. The field plant applications have been the subject of lengthy hearings which have enabled the ERCB to decide individual applications based on certain public interest criteria, but have done little to resolve the fundamental dispute between the parties.

In August 1987, the Alberta Government issued a policy statement that outlined its position respecting the extraction of ethane in the province. The policy established certain "rules" intended to ensure that both industries in the province that currently use ethane would have access to adequate and competitive sources of supply. The basis of the policy is the setting of a guaranteed "threshold volume" of ethane that could be extracted and supplied to the Project from its straddle plants.

Upon the announcement of the new policy, the Government requested the Board to consult with interested parties regarding several specific issues relating to the policy's implementation. Following an initial consultation, there was consensus between the parties that a public inquiry would be the appropriate forum for the Board to hear the views of all interested parties.

The Board convened the inquiry on 26 October 1987 to consider the following specific issues as requested by the Government:

1. the determination of the ethane facilities which should be affected by or be part of this policy;

2. the principles that should be used in determining the threshold volumes and the actual volumes thereby determined;

3. the determination of the procedures for requiring and the mechanism for ensuring reinjection or supply of ethane to the straddle plant system;

4. procedures that should be used for the expedient regulatory processing of applications for field ethane extraction facilities;

5. the existing and potential efficiency of ethane extraction at the straddle plants, the investment required to enhance extraction, and potential linkages with threshold volumes;

6. any legislative changes required to implement the policy; and

7. any other relevant matters.

Some 26 interested parties participated in the inquiry by presenting their views and/or questioning other participants. The positions of the participants on the six issues can be generally aligned into two sets of views, with variations of the basic positions put forth by some. The key issues where views were widely divergent related to whether the threshold volume should be defined at the inlet or output from the straddle plants, the magnitude of the threshold volume, and the terms of reinjection or supply of ethane to the Project to maintain the threshold volume.

The Project's position with respect to the threshold level was that it should assure the availability of sufficient ethane at the straddle plants to meet the requirements of the two existing ethylene plants as well as some volume for marketing until such time as it is needed to supply the Project's proposed third ethylene plant. The threshold volume recommended by the Project was defined in terms of the output from the straddle plants and was in the order of 21.5 to 23.9 x 10^3 m^3/d (135 to 150 x 10^3 bbl/d) of specification ethane.

Gas producers argued that the provision in the policy for a threshold volume or guaranteed supply for the Project was unfair because it imposed an obligation on the gas industry for the benefit of the Project. If a threshold volume were to be implemented, however, producers generally recommended that it be limited to the maximum ethane feedstock needed to meet the initially-approved throughput rates of the Project's two ethylene plants. Some producers suggested that it be defined in terms of a gross inlet volume to the straddle plants. This would amount to some

12×10^3 m^3/d (75×10^3 bbl/d) of straddle plant ethane output or 17×10^3 m^3/d (107×10^3 bbl/d) of inlet volume taking into account current straddle plant efficiency levels.

The gas producers also objected to the reference in the policy to the price that would be paid to field plant owners for ethane required to maintain the threshold volume for the Project and argued that the required transfer of ownership of ethane to the Project at a price set by the policy would be confiscatory.

The Project supported the price to be paid for any restored ethane volume as "the incremental cost of ethane extraction at the straddle plants" as described in the policy statement.

In formulating its recommendations respecting the policy, the Board reviewed the relevant letters exchanged between Project proponents and Government ministers in 1975, 1976, and 1985, and concluded that there were no specific volume or time-period commitments made by the Government respecting ethane supply to the Project. It therefore based its recommendations for implementation of the policy on measures it believes would best serve the Alberta public interest.

In its recommendations, the Board has proposed measures which it believes would be reasonably workable, fair to affected parties, and which would attempt to minimize the need for ongoing regulatory and Government involvement.

The Board's recommendations were influenced generally by its conclusion that the potential supply of ethane in the province is substantially higher than the expected Alberta demand. This conclusion is based on the Board's own forecast of the supply and demand situations over the next 20-year period.

The Board's main recommendations are listed below.

Facilities that should be part of policy

- The policy should provide protection only for the feedstock requirements of petrochemical plants which were approved and operating, or under construction at the time of announcement of the policy.

- Field plants recovering ethane which were approved and operating, or under construction at the time the policy was announced, should not be subject to the condition to supply ethane to support the threshold volume. If such plants undergo major expansion or if substantial new reserves are connected to them, the expansion or new reserves should be made subject to such a condition. New field plants recovering ethane should be subject to the condition. Exceptions would be where the lean residue gas is not destined to a stream which would be subsequently processed by a straddle plant.

The definition and setting of the threshold volumes

- The approximate debottlenecked capacity of the existing ethylene plants, 14.2 x 10^3 m^3/d (89.3 x 10^3 bbl/d) of pure ethane[1], should be protected as part of the threshold volume. Planned expansions to existing ethylene facilities and new facilities should not be included because the necessary investments have not as yet been made. The ethane marketing component of the Project should not be included in the threshold volume other than a minimum volume of 500 m^3/d (3 x 10^3 bbl/d) of pure ethane for use as a buffer to move ethylene batches through the Cochin pipeline.

- The threshold volume should be expressed on the basis of ethane at the inlet of the straddle plants. Such a system would be administratively less complex and would encourage upgrading of the straddle plants because the increased recovery of the ethane available would increase supply and the increased supply would not be subject to the effects of additional upstreaming. The capacity of the existing ethylene plants and the required buffer volume, when adjusted for straddle plant recovery efficiencies, results in a threshold volume at the inlet of the Project straddle plants of 19.6 x 10^3 m^3/d (123 x 10^3 bbl/d) of pure ethane. This would be in addition to some 950 m^3/d (6 x 10^3 bbl/d) committed to the Project from field plants.

- The protection for the two existing ethylene plants should be for the terms of the respective industrial development permits. Each of these was initially for 20 years. This would mean the full threshold volume of 19.6 x 10^3 m^3/d (123 x 10^3 bbl/d) would be provided until the end of 1998. The protection would then reduce to 10 x 10^3 m^3/d (63 x 10^3 bbl/d) through to the end of the year 2004.

Procedures for supplying ethane to the straddle plant system

- The Government should reconsider the position put forward in the policy statement that the price to be paid for field plant reinjected or directly-supplied ethane would equal the incremental cost of extracting the ethane at the straddle plants. As an alternative that would be more in the public interest, the price to be paid for such

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1 Specification ethane is approximately 94 per cent ethane and therefore volumes expressed as specification ethane are some 6 per cent larger than when expressed as pure ethane.

ethane should be negotiated between buyer and seller. The relevant legislation should be changed to provide for a fair price to be set by a neutral third party in those situations where a price cannot be negotiated.

- For those plants which are required to provide ethane to the Project to maintain the threshold inlet volume, all of the Crown royalty ethane should be utilized first before any freehold royalty or working-interest ethane is subject to the requirement. Crown royalty ethane from those plants not subject to the requirement to supply the Project should not be affected by the policy. This would not preclude the Crown taking such royalty ethane in kind and providing it to the Project if it so desired.

- Supply of ethane to the Project should be by negotiation where feasible but would be ordered by the Board if negotiations for volumes to satisfy the threshold failed.

Procedures to be used for expedient processing of field plant applications

- The Board would approve any ethane extraction application, without hearing or notice, if it were satisfied that conservation, social, and environment requirements were met, and if the scheme were in the public interest; and approval would be in accordance with the ethane policy.

1 INTRODUCTION

This report is in response to a request by the Government of Alberta that the Energy Resources Conservation Board (the Board or ERCB) consult with the industry regarding the Government's policy on ethane and report to it on a number of aspects of the implementation of the policy.

The report provides background to the request and identifies those who participated in the Board's public inquiry respecting the matter. It also briefly summarizes the positions taken by the various participants.

To assist the reader, Section 2 of the report describes the provincial ethane system and the roles played by the various parties, most of whom participated in the inquiry.

Section 3 gives the Board's projection of ethane supply and demand in Alberta over a future period of 20 years. These projections served as background to the Board's consideration of the various matters before it.

A brief discussion of the policy and the issues which the Board sees as relevant in its considerations is contained in Section 4 of the report, and the details of those considerations are set out in subsequent sections.

1.1 Background

On 21 August 1987, the Government issued a policy statement outlining its position respecting the production and use of Alberta ethane. (A copy of the policy statement is included in Appendix 1A.) The stated goal of the Government policy is

"...to maintain a functioning market in ethane wherein both the petroleum and petrochemical industries will have access to adequate and competitive sources of ethane supply and the incentive for further development of ethane-related activity in the province."

The policy was developed in response to a continuing conflict between gas producers and the Alberta ethane-based petrochemical industry regarding the right to extract ethane from natural gas in the province.

Ethane feedstock for ethylene production in Alberta is almost totally supplied from a small number of reprocessing plants (straddle plants) that extract natural gas liquids from gas previously processed and carried in main transmission pipelines before the bulk of it leaves the province and the remainder is consumed within the province. When the Alberta Ethane/Ethylene Petrochemical Project (the Project) was being planned in the early 1970s, the extraction of ethane at straddle plants

was considered by proponents to be the only feasible method of supplying the large volumes of ethane necessary to establish the contemplated world-scale ethylene plants. By the late 1970s ethane extraction capability at the straddle plants was being applied for and put in place to coincide with the start-up of the first ethylene plant. Gas producers were warning at that time that in future they might want to extract ethane at plants located in fields (field plants) upstream of the straddle plants.

In the early 1980s, a growing market for ethane-rich natural gas liquids (NGL) for use in miscible flood enhanced oil recovery (EOR) resulted in serious interest in ethane recovery at some field plants. Several field plants located upstream of the straddle plants have been applied for, approved, and built since 1981.

The Project has continuously opposed such applications for field ethane extraction on the basis that extraction in the field reduces the volume and concentration of ethane entering the straddle plants and thereby increases the cost of ethane feedstock output from the straddle plant system. Additionally, it has been argued that ethane extraction facilities upstream in the fields are largely duplicative of ethane extraction capability at the straddle plants; thus, there is little or no benefit to the province deriving from the field plants.

Proponents of field plants, generally gas producers, many of which are also oil producers interested in miscible-flood EOR, have argued that a mix of NGL, including ethane and heavier hydrocarbons (ethane-plus), produced at field plants is technically better suited and geographically better located to satisfy the demand for solvent used in hydrocarbon miscible flood operations.

In its assessment of individual applications to extract ethane in the field, the Board has used a number of criteria to determine whether or not approval of an application would be in the public interest. These criteria included the degree to which the proposed facilities would extract ethane incremental to the amount that could be extracted without the facilities, whether a market would exist for the ethane that could be extracted, the cost of supply of the ethane at a field plant compared with other supply sources, the impact on the straddle plant system and on the ethane-based petrochemical industry, the impact on the potential for EOR, the economic benefits to Alberta, proprietary rights, the degree of upgrading of resources within Alberta, and conservation and environmental considerations.

Applications to extract ethane in the field have typically resulted in lengthy public hearings before the Board where producers and the Project have argued details of cost/benefit analyses, supply and demand forecasts, and proprietary rights. Producers have been dissatisfied with the extensive information requirements common to these applications and

with the project delays caused by the hearing process. On the other hand, the Project has been dissatisfied with the need to oppose each application individually, and generally has been disappointed with the Board's ultimate decisions to approve most applications. To date, the Board has approved eight such applications and denied one. Four of the approved applications involved cycling schemes.

Since announcement of the policy, the Board has deferred two additional applications to extract ethane in the field pending implementation of the policy and has granted conditionally two other applications to extract ethane at gas cycling schemes.

As an alternative to resolve disputes between the producers and the Project over the right or authorization to extract ethane and the extraction location, the Board believed there was potential for negotiation of arrangements suitable to both the upstream and downstream interests. The Board encouraged such negotiation to the extent of making its approval of three applications in 1982 conditional on such negotiations taking place and encouraging future applicants to seek a negotiated settlement prior to seeking approval from the Board. In every case the negotiations failed or were only minimally successful.

1.2 Inquiry

On 21 August 1987, the Board received a copy of the Government policy statement under cover of a letter from The Honourable Dr. N. Webber, Minister of Energy. (Copies of the letter and policy statement are included in Appendix 1A.) In the letter, the Minister requested that the Board consider and report on the policy for protection of threshold volumes of ethane for the Project with specific reference to the following matters:

1. the determination of the ethane facilities which should be affected by or be part of this policy;

2. the principles that should be used in determining the threshold volumes and the actual volumes thereby determined;

3. the determination of the procedures for requiring and the mechanism for ensuring reinjection or supply of ethane to the straddle plant system;

4. procedures that should be used for the expedient regulatory processing of applications for field ethane extraction facilities;

5. the existing and potential efficiency of ethane extraction at the straddle plants, the investment required to enhance extraction, and potential linkages with threshold volumes;

6. any legislative changes required to implement the policy; and

7. any other relevant matters.

The Board notified interested parties of the policy statement and held a planning meeting on 1 September 1987 to determine the best way to allow affected parties' input to the Board's consideration of the policy. There was general agreement at the meeting that a public hearing process would be necessary to inquire into the matters raised by the Government. In its Memorandum of Decision dated 8 September 1987, the Board outlined the terms of reference for the inquiry to begin on 26 October 1987.

Prior to the start of the inquiry, the Board received submissions from 26 interested parties.

The inquiry commenced, as scheduled, on 26 October 1987, with G. J. DeSorcy, P.Eng. (Chairman), N. A. Strom, P.Eng., and F. J. Mink, P.Eng., sitting. A list of the registered participants is contained in Appendix 2 to this report. Appendix 3 contains a brief summary of the views of the participants.

The inquiry was in session a total of 20 days between 26 October and 14 December 1987. Written final arguments and responses were filed with the Board on 15 January and 22 January 1988, respectively.

2 PROVINCIAL ETHANE SYSTEM AND ROLE OF VARIOUS PARTIES

In Alberta, ethane is primarily recovered by extraction from natural gas streams at straddle plants and field plants. Crude oil refineries[1] are also sources but represent a relatively small portion of the total supply. Commercial ethane production from straddle and field plants is dependent on several factors, including the volume of natural gas processed, ethane content of the gas, and recovery level achievable by the type of plant.

Extracted ethane takes the form of either specification ethane[2] from major gas pipeline straddle plants and some field plants or the form of an ethane-plus mixture often including large proportions of propane and butanes from field facilities. The specification ethane is primarily used at ethylene manufacturing facilities while the ethane-plus is primarily used as a miscible flood solvent for EOR.

In 1987 Alberta produced some 20×10^3 m^3/d of specification ethane and approximately 8×10^3 m^3/d of ethane in the form of ethane-plus.

Figure 2-1 is a conceptual diagram of the network of ethane facilities in Alberta. Figure 2-2 is a map showing the locations of the facilities.

There are six straddle plants in Alberta, one at Cochrane, one at Ellerslie, and four at Empress as shown in Figure 2-2. The Cochrane plant which is owned by Alberta Natural Gas Company Ltd (ANG) processes gas that is primarily destined for export to the southwestern part of the United States (U.S.). The gas entering this plant tends to be fairly rich in ethane content. The design gas throughput capacity at the ANG plant is 31.2×10^6 m^3/d.

The Ellerslie (South Edmonton) plant, owned by Dome Petroleum Limited (Dome) and ATCOR Resources Limited, is a smaller plant with design gas throughput capacity of 9.8×10^6 m^3/d. It processes selected natural gas streams destined for use in the Edmonton area.

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1 Ethane is technically available from oil sands upgrading operations. Such a source is not expected to be commercial in the near future and therefore is not dealt with in this report.

2 Specification ethane contains approximately 94 per cent ethane. In this report ethane volumes are expressed in cubic metres of pure ethane, unless otherwise defined.

There are four straddle plants at Empress to process gas serving ex-Alberta markets to the east. These are Dome Empress I, owned by Dome and PanCanadian Petroleum Limited (PanCanadian), with a design gas throughput capacity of 41.5 x 10^6 m^3/d; Dome Empress II, owned by Pan-Alberta Resources Inc. and TCPL Resources Ltd., with a design gas throughput capacity of 55.4 x 10^6 m^3/d; the Petro-Canada Inc. (Petro-Canada) Empress plant, owned by Petro-Canada and PanCanadian, with a design gas throughput of 67.6 x 10^6 m^3/d; and the Empress Gas Liquids Joint Venture (EGLJV) plant, owned by fifteen different entities, with a capacity for processing 9.9 x 10^6 m^3/d of natural gas. The combined gas throughput design capacity at Empress is therefore 174.3 x 10^6 m^3/d. The gas entering these plants tends to be quite a lot leaner than that entering the ANG Cochrane plant.

Most of the ethane extracted at the straddle plants is dedicated to Alberta Gas Ethylene Company Ltd. (AGEC) for manufacturing of ethylene. Some ethane extracted at the EGLJV plant and at the Dome/ATCOR Ellerslie plant is contracted to other users.

There are also three field plants which produce specification ethane. These plants are located in the Waterton, Jumping Pound, and Turner Valley fields. The gas throughput capacities of these plants are 7.7, 5.2, and 0.6 x 10^6 m^3/d, respectively.

Table 2-1 contains the design capacity specifications for the facilities which supply specification ethane to the Project. The ethane extracted at these plants is gathered and transported in the Alberta Ethane Gathering System (AEGS) which is operated by Dome. As illustrated in Figures 2-1 and 2-2, ethane from the straddle plants is transported to AGEC ethylene facilities at Joffre or onward to cavern storage facilities at Fort Saskatchewan. The storage facilities at Fort Saskatchewan currently dedicated to ethane are owned by Dome, Chevron Canada Resources Limited (Chevron), Procor Limited, and Dow Pipeline Limited; and together they have capacity to store up to 800 x 10^3 m^3 (5 x 10^6 bbl) of ethane.

Ethane that is surplus to AGEC's feedstock requirements is marketed under the Cochin Ethane Marketing Joint Venture (CEMJV) agreement among Dome, Dow Chemical Canada Inc. (Dow), NOVA, an Alberta Corporation (NOVA), Petro-Canada, and Shell Canada Limited (Shell). The main market for this ethane originally was a fuel market in the U.S. Ethane was transported in the Cochin Pipeline to Sarnia, Ontario, where some was sold and to Greensprings, Ohio, the main market. The Cochin Pipeline runs from the cavern storage near Edmonton through Saskatchewan, connecting to pipelines to the U.S. midwest markets and ends at Sarnia, Ontario. Since the loss of the Greensprings contract in early 1986, CEMJV has had to seek other markets. Since 1985 it has marketed some specification ethane to miscible flood operations in Alberta. The latter is transported in the Federated Pipeline system from Fort Saskatchewan to oil fields in the Swan Hills area.

Ethylene manufactured at Joffre by AGEC is transported through AGEC's ethylene pipeline to storage at Fort Saskatchewan, to Alberta ethylene derivative manufacturers, or to Sarnia. Ethylene is batch-shipped to Sarnia in the Cochin pipeline with batches of ethane and other NGL products. Ethane is also used as a buffer to reduce contamination of the ethylene batches while in the pipeline.

Ethylene derivatives manufactured in Alberta include styrene, ethylene dichloride, vinyl chloride monomer, ethylene oxide, ethylene glycol, polyethylene, vinyl acetate, and linear higher olefins. The current major ethylene derivative manufacturers in Alberta are Dow, Union Carbide Ethylene Oxide/Glycol Company (Union Carbide), C-I-L Inc. (C-I-L), Celanese Canada Inc. (Celanese), Novacor Chemicals Ltd. (Novacor), and Shell.

Ethane-plus is extracted at a number of field plants, usually close to EOR schemes, in Alberta. There are six field plants currently extracting ethane-plus, another which is capable of producing specification ethane, and an additional plant under construction which will extract ethane-plus by 1989. The design capacities for gas and ethane of these facilities are tabulated in Table 2-2. These plants are sometimes referred to as deep-cut field plants and are not part of the Project.

A small straddle plant that is not part of the Project, the Norcen plant, is located at Fort Saskatchewan and produces ethane-plus. It has a throughput capacity of 1.0×10^6 m^3/d of natural gas. This plant extracts liquids from gas destined for use in the Edmonton area.

The ethane-plus from these field plants is currently injected as part of the solvent in EOR schemes. Ethane-plus is transported from various plants to miscible flood projects via the Peace Pipeline system, the Federated Pipeline system and the Amoco Pembina Pipeline system.

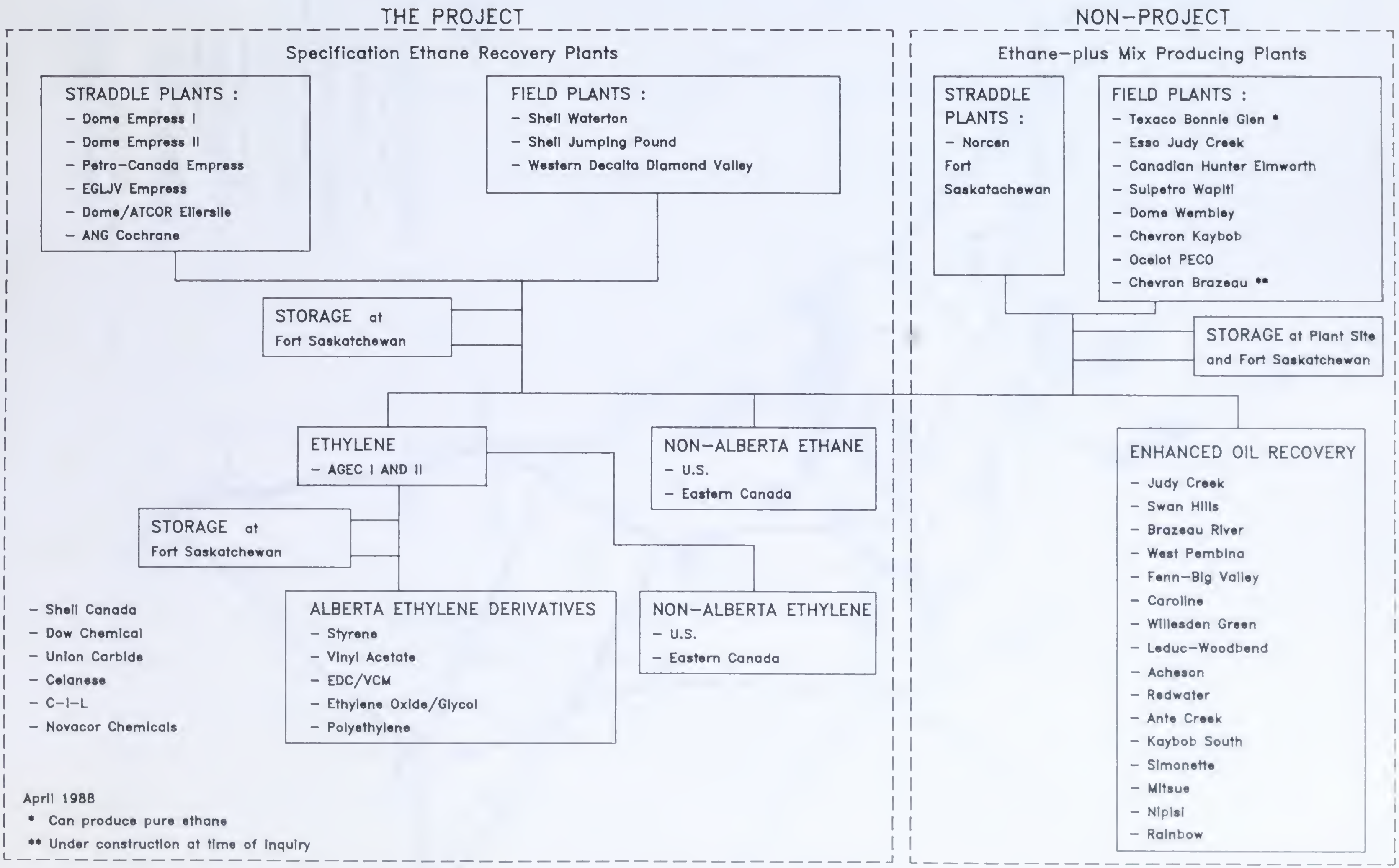

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FIGURE 2–1 CONCEPTUAL DIAGRAM OF THE ALBERTA ETHANE NETWORK

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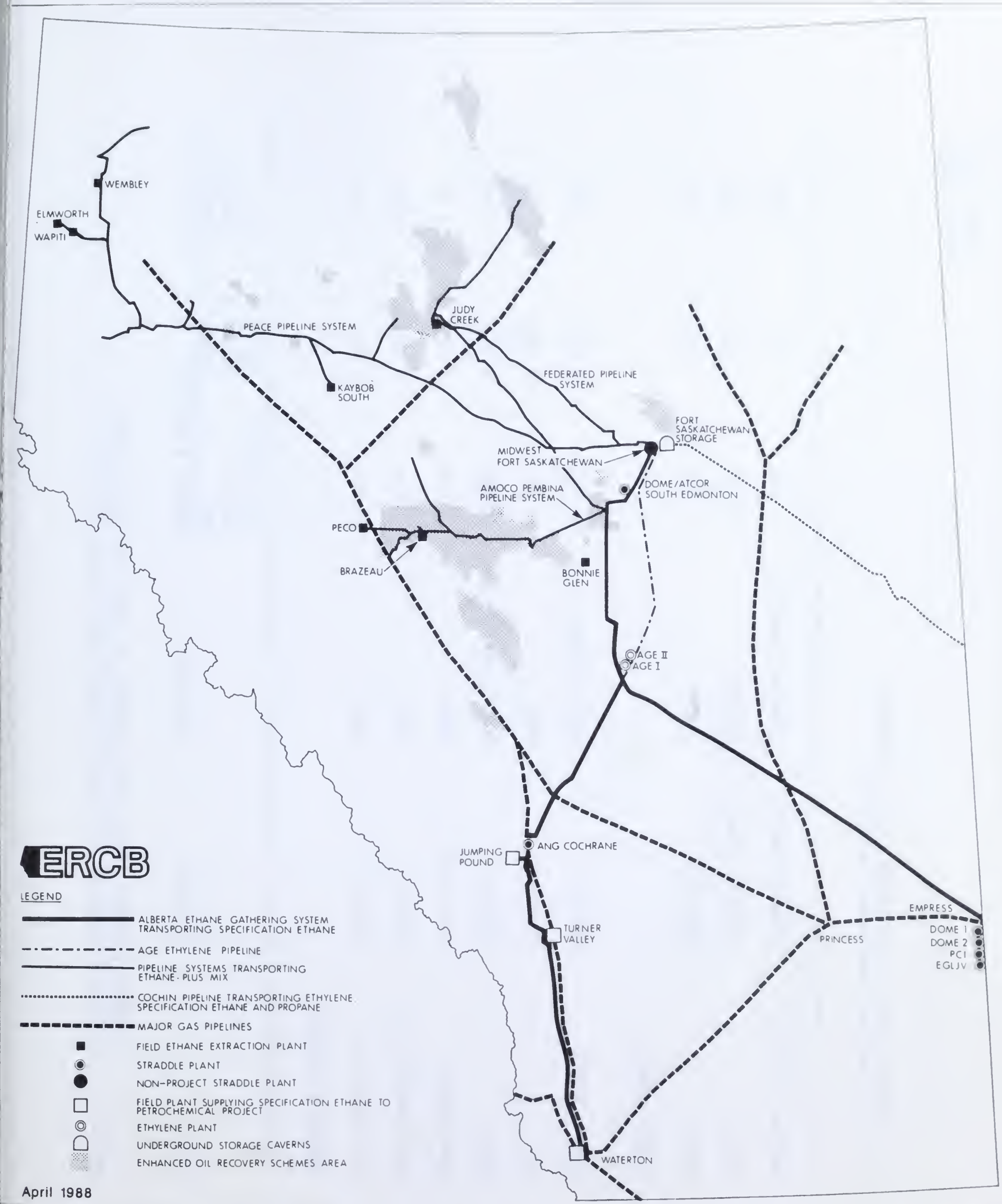

FIGURE 2-2 ALBERTA ETHANE NETWORK

TABLE 2-1 ETHANE EXTRACTION FACILITIES CONTRACTED TO THE PROJECT
(ETHANE NUMBERS SHOWN ARE REPORTED IN TERMS OF PURE ETHANE)

NAME	LOCATION	OPERATOR	DESIGN CAPACITY		
			Gas Inlet (10^3 m^3/d)	Ethane Recovery (m^3/d)	Ethane Content (%)
STRADDLE PLANTS					
Dome Empress I	Empress	Dome	41 500	2 703	5.15
Dome Empress II	Empress	Dome	55 400	5 287	3.83
Dome/ATCOR	Ellerslie	Dome	9 750	2 397	12.95
EGLJV	Empress	D. M. Wolcott[a]	9 860	1 113	4.15
ANG	Cochrane	ANG	31 150	6 592	7.18
Petro-Canada	Empress	Petro-Canada	67 620	5 079	3.95
FIELD PLANTS					
Shell	Waterton	Shell	7 748	911	5.08
Shell	Jumping Pound	Shell	5 212	431	3.88
Western Decalta	Diamond Valley	Western Decalta[b]	564	190	10.96

a D. M. Wolcott and Associates Ltd.
b Western Decalta Petroleum (1977) Limited.

TABLE 2-2 ETHANE EXTRACTION FACILITIES NOT CONTRACTED TO THE PROJECT (ETHANE NUMBERS SHOWN ARE REPORTED IN TERMS OF PURE ETHANE)

NAME	LOCATION	OPERATOR	DESIGN CAPACITY		
			Gas Throughput (10^3 m^3/d)	Ethane in Ethane-plus (m^3/d)	Ethane Content (%)
STRADDLE PLANTS					
Norcen	Fort Saskatchewan	Norcen	995	162	5.12
FIELD PLANTS					
Chevron	Kaybob South	Chevron	6 294	1 808	8.84
Chevron[a]	Brazeau	Chevron	667	322	13.96
Canadian Hunter	Elmworth	Canadian Hunter	7 748	1 752	7.15
Dome	Wembley	Dome	2 803	890	10.24
Esso	Judy Creek	Esso	3 800	2 915	28.00
Ocelot	Peco	Conoco	986	392	12.26
Sulpetro	Wapiti	Sulpetro	10 028	1 787	5.79
Texaco[b]	Bonnie Glen	Texaco	1 385	1 099	18.39

a Under construction at time of inquiry.
b Ethane can be produced as ethane-plus or pure ethane.

3 FORECAST ETHANE SUPPLY AND DEMAND

To aid in formulating a threshold volume system and to understand how it might be administered, the Board found it useful to have a reasonable picture of future ethane supply from Alberta natural gas and demand for ethane in the province. While some participants looked at the supplies potentially available, the Board's 20-year forecasts have been prepared on the strength of its own information only and would not necessarily be used in administering any future system for the maintenance of a threshold volume. If, as a result of the recommendations set out in this report, a system is implemented that would require periodic forecasting of supply and demand, the Board would likely request submissions from interested parties in order to have detailed information on which to base its forecast.

3.1 Supply

The Board's forecast of potential ethane supply over the next 20 years is shown on Figure 3-1. Several years of historical supply are also shown. It should be emphasized that the forecast is of a "potential" supply. The degree to which ethane will actually be supplied from the various gas streams will depend on the demand for ethane.

Potential supply from the straddle plant system is based on forecast gas throughputs at the Empress, Cochrane, and Edmonton facilities. These reflect the Board's views regarding the province's ultimate gas and oil reserves potential, future discovery rates, and future demand for Alberta gas.

The evidence presented at the inquiry clearly indicated that there is potential to improve ethane extraction efficiencies at some of the straddle plants. The Board believes that some efficiency increase at the straddle plant system will probably occur in the future, perhaps to coincide with a large increase in demand such as from the next ethylene plant, and has assumed a degree of this effect in its forcast of potential straddle plant supply.

In forecasting the potential supply, the Board has also assumed that implementation of the policy will not halt the construction of new upstream field plants. The Board believes this to be consistent with the policy statement. As well, the Board sees substantial potential for creating new ethane supply by extracting ethane at gas cycling schemes that would not have an upstreaming effect on the straddle plant system until the blowdown phase of the reservoir.

It will be noted from Figure 3-1 that the Board has used a broken line to divide forecast potential supply from the straddle plant and field systems. This is to reflect uncertainty as to which plants the volumes

would be recovered at and to emphasize that some volumes potentially supplied by field plants could be supplied by straddle plants, and vice versa.

The Board has also added as a third component to its forecast supply, ethane-rich gas reproduced from miscible flood EOR schemes. Here again, the degree to which this supply will be tapped will be largely dependent on the development of markets for the ethane. As well, the locations at which reproduced gas rich in ethane would be processed, ie. at upstream field or downstream straddle plants, will depend on a number of factors at the time the ethane-rich gas is being reproduced from the reservoir.

Figure 3-1 shows that the potential ethane supply could increase from the current level of about 24 x 10^3 m^3/d (151 x 10^3 bbl/d) to some 40 x 10^3 m^3/d (252 x 10^3 bbl/d) by the mid-1990s. It would then decline gradually for many years. Of course, the extent to which the ethane is actually supplied will depend on market demand. The portion which will be supplied by field plants, as opposed to straddle plants, is also uncertain, but the figure suggests it could grow to as much as one-third and then diminish with time.

3.2 Demand

The Board has prepared two demand cases shown on Figure 3-2. Several years of history are shown in addition to a 20-year forecast. For the low case shown on Figure 3-2, the Board has considered what is essentially a no-growth situation in demand for Alberta ethane. This case assumes that demand for ethylene manufactured in Alberta remains at about the 1987 level and neither debottlenecking of existing ethylene plants nor construction of a third ethylene plant occurs. The petrochemical demand includes a minimal amount of ethane to buffer ethylene shipments on the Cochin Pipeline system. This case also assumes that the demand for ethane for EOR solvent injection peaks in 1989 and declines quite rapidly thereafter.

The figure shows that for the low case, ethane demand would not grow much above the current levels of 24 x 10^3 m^3/d (151 x 10^3 bbl/d) and indeed would decline to about 18 x 10^3 m^3/d (113 x 10^3 bbl/d) and remain flat thereafter. The Board has included this no-growth case as an illustration of the very minimum ethane demand, though it generally believes it is overly pessimistic to expect such a situation.

The second demand case is higher and, in the Board's view, more realistic. This forecast assumes that demand for Alberta ethylene would warrant the debottlenecking of the two ethylene plants before 1990 as well as the construction of a third ethylene plant in the province by the early 1990s. For this more optimistic demand case, the Board has also forecast somewhat increased EOR activity by extending the peak requirement beyond 1989, assuming that availability of ethane could promote additional EOR use.

Figure 3-2 shows that ethane demand could grow to as much as 31 x 10^3 m^3/d (195 x 10^3 bbl/d) by 1993 and would then decline to about 27 x 10^3 m^3/d (170 x 10^3 bbl/d) by the late 1990s.

3.3 Comparison of Potential Supply to Demand

Figure 3-3 compares potential ethane supply to the forecast no-growth and realistic demand cases assuming no transportation constraints. On the basis of this comparison, the Board concludes that over the 20-year forecast period, sufficient ethane should be available from Alberta gas production to fully satisfy intra-Alberta requirements, including an expanded ethylene industry. Indeed, the forecasts suggest that enough ethane could be available to serve substantial extra-provincial markets if they were developed. This tends to confirm the views expressed by participants at the inquiry and by the Government in its policy statement.

The projections shown in these figures will be used by the Board as a background in its consideration of the matters before it.

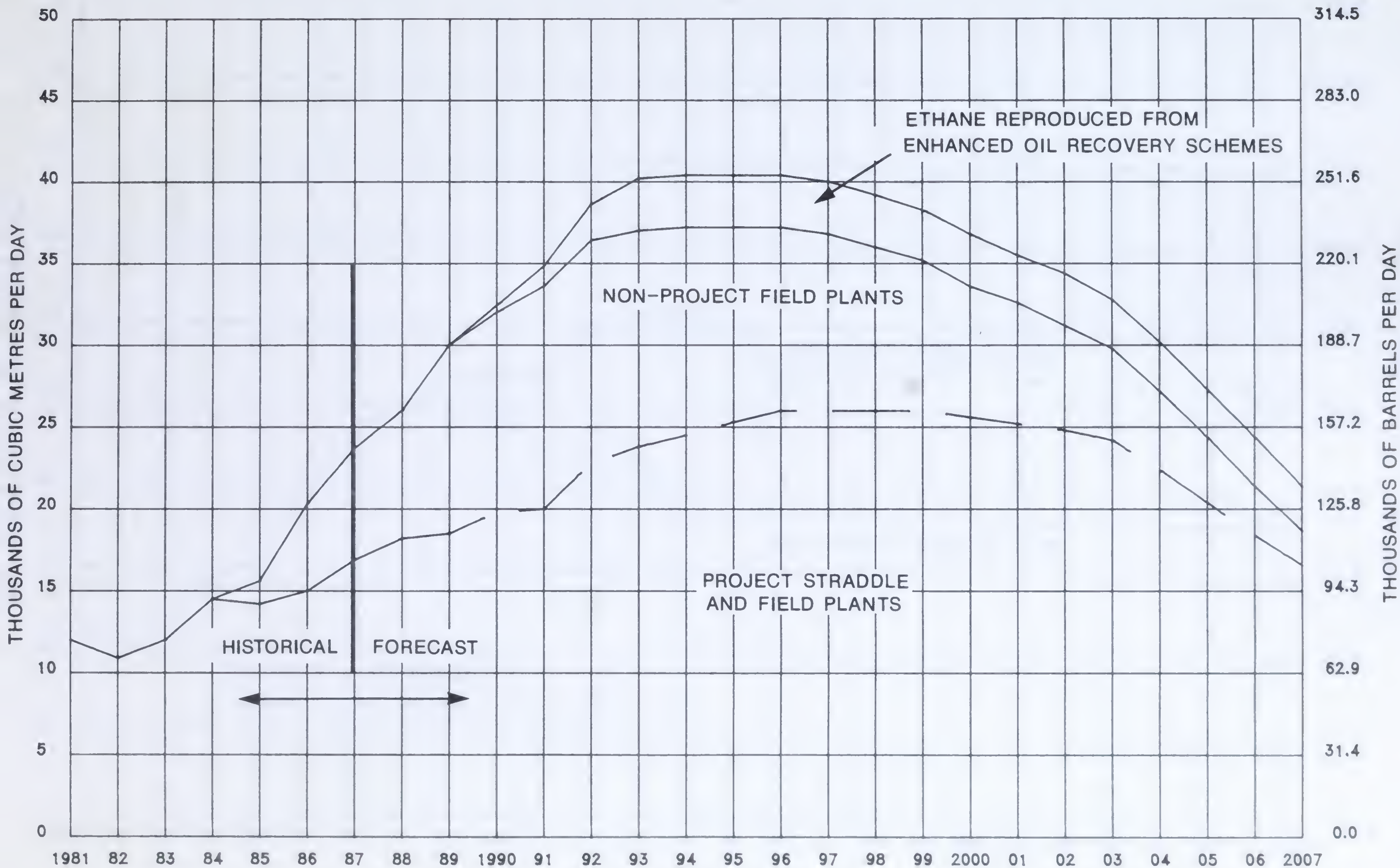

FIGURE 3-1 POTENTIAL ETHANE SUPPLY

D 88-D

ERCB

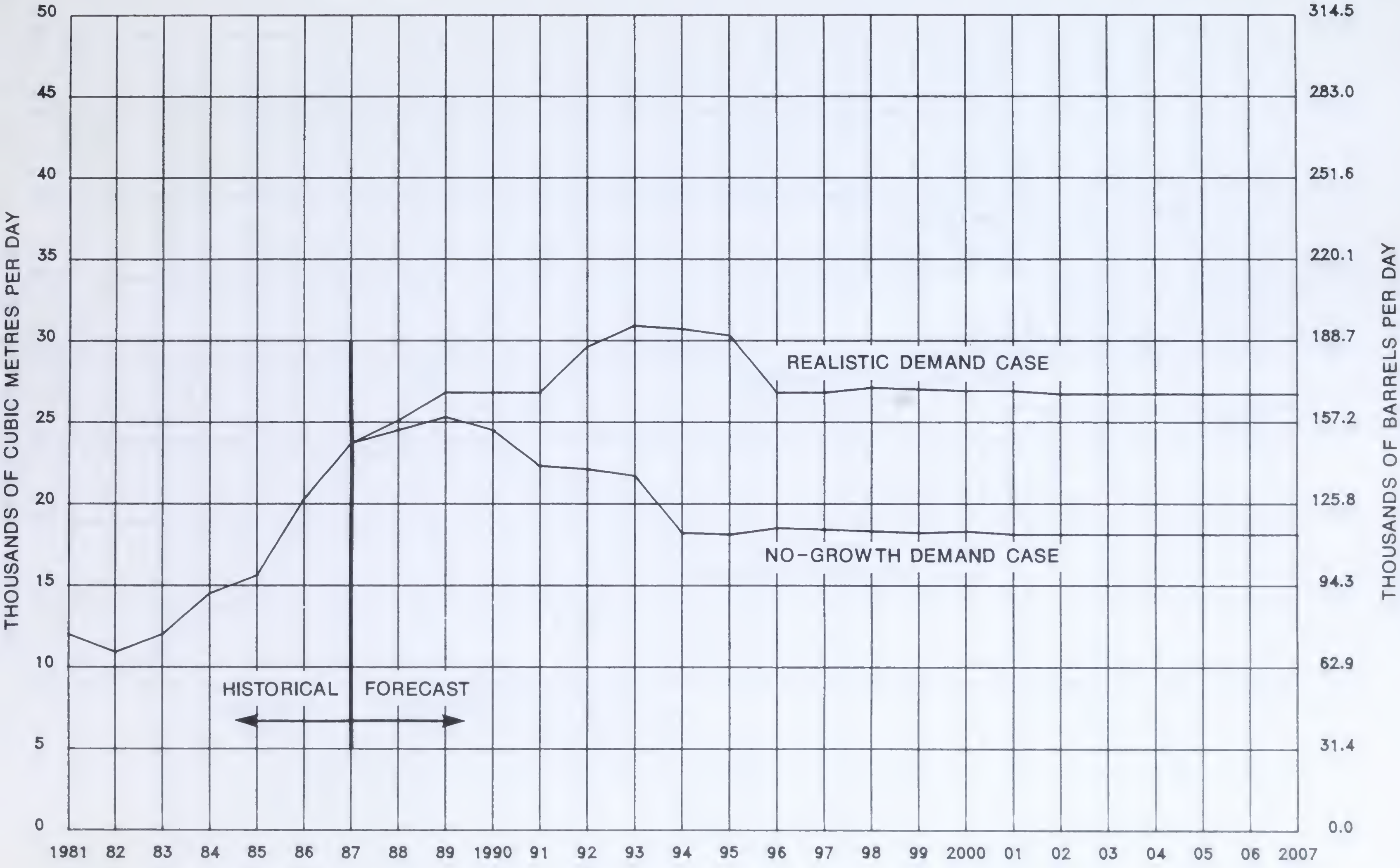

FIGURE 3-2 ETHANE DEMAND

D 88-D
ERCB

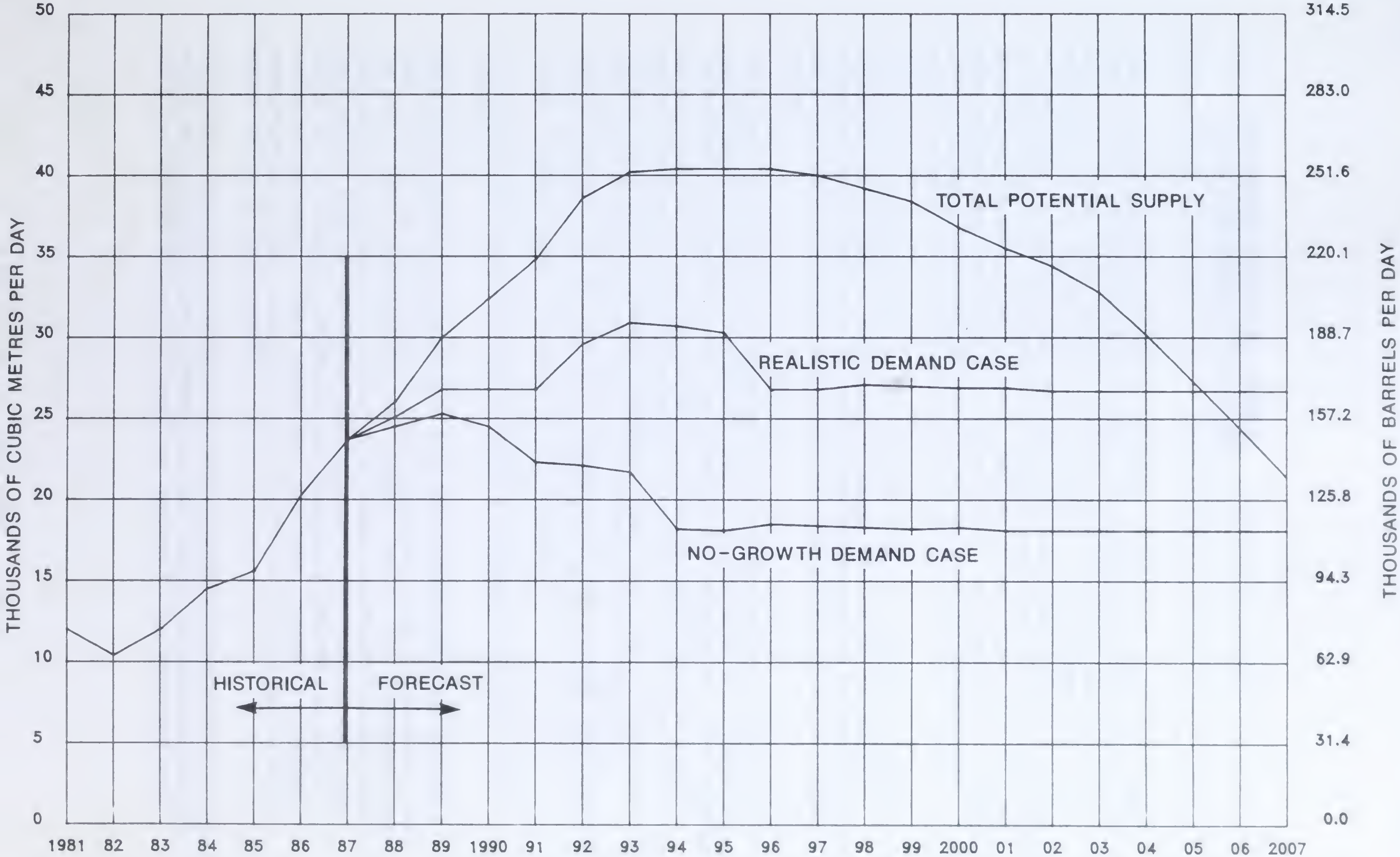

FIGURE 3-3 COMPARISON OF POTENTIAL SUPPLY TO DEMAND

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ERCB

4 THE ETHANE POLICY AND ISSUES TO BE CONSIDERED BY THE BOARD

4.1 Policy

The previously mentioned policy statement of the Government (21 August 1987) set out certain objectives for, and principles to be embodied in, a policy with respect to ethane. The letter of the same date from The Honourable Dr. N. Webber, Minister of Energy, to the Board indicated "...the need for further consultation with the industry and consideration of the policy, its implementation, and any amendments to the legislation required to implement the policy." It went on to request "...that the ERCB consider and report on the ethane policy, with particular reference to the following specific matters:....". It then identified seven matters related to the implementation of the policy.

The Board's interpretation of the request from the Minister, insofar as a review of the policy is concerned, is summarized in the following paragraph taken from its 8 September 1987 Memorandum of Decision arising out of a planning meeting respecting the implementation of the ethane policy.

"Although there were some requests for allowing the widest possible opportunity to speak to the policy itself, in the Board's interpretation, the Minister's request is not for a detailed review of the ethane policy and alternatives to it, but rather to have the Board focus on specific aspects pertaining to implementation as set out in his letter and listed above. Therefore, the Board intends to limit the scope of the inquiry to these specific matters and any other relevant matters respecting implementation. In the course of doing so, it will accept consideration of the policy to the extent that it bears on the practical matters of policy implementation as listed by the Minister."

The inquiry was conducted more or less in accordance with the above statement.

Those participants in the inquiry from the petrochemical and straddle plant side of the matter (the Project) generally took the position that the policy was a reasonable one and argued that "...the Government has finalized the policy...". On the other hand, those participants from the gas producer side of the matter generally took the position that the policy was "...wrong in principle and completely unnecessary for a variety of reasons." They argued that the Board's mandate included a consideration of the policy and urged the Board "...to consider and report on the policy itself."

The inquiry was not structured to provide a detailed review of the policy and it would therefore be improper for the Board to extensively advise the Government on the policy itself as opposed to its implementation.

The Board should make clear, however, that certain matters which might be considered basic elements of the policy could be affected by some of the Board's recommendations on implementation. Additionally, the Board considers it appropriate to comment from its perspective on the background to the policy statement and the need for a policy.

The Board has, on numerous occasions, made clear its views that the overall most efficient ethane extraction system for the province would include a combination of appropriately-located straddle and field plants. In the Board's judgement the blend of straddle and field plants should ideally be established on the basis of "commercial decisions". Under ideal circumstances regulatory involvement should be limited to that necessary to ensure that the facilities satisfy the public interest in terms of conservation and impacts on the community and environment. Where conflicts respecting commercial decisions occur, the Board strongly believes that negotiation towards mutually acceptable arrangements is the most suitable course of action.

Unfortunately efforts in this direction have not been successful, so the Board has been required to continue to exercise its jurisdiction and discharge its responsibilities as it interpreted them. This has meant providing notice of ethane extraction applications to parties that could be directly and adversely affected, and as appropriate, assessing whether such applications would provide for the economic, orderly, and efficient development in the public interest of the resources of the province.

The Board's method of assessing these applications over the past 7 years or so has had several less than satisfactory aspects. One of them is that the parties on both sides of the issue, the Project and the gas producers, face considerable uncertainty and do not know what the outcome of individual applications might be until they are assessed in detail and ruled on by the Board. The cost and time delays related to the processing of the applications have also been very substantial for all parties including the Board. Because of the shortcomings, the Board has over the years considered many possible "policy or system changes" which might improve the situation. Its objective was to seek an approach which would

- be workable,
- be fair to interested parties, and
- minimize the need for Government or regulatory intervention in what should normally be commercial decisions.

It has, quite frankly, failed to come up with any one approach which stood out with respect to all of these objectives.

The Board interprets the objectives of the Government as described in the 21 August 1987 policy statement to be similar to those expressed above.

On the basis of its knowledge of the industry and the evidence submitted at the inquiry, the Board believes the Government policy is a workable one, even though it may require a relatively complex administrative system to implement it.

When dealing with an issue as controversial and emotional as the ethane policy, it is not reasonable to expect all involved parties to see any one approach as totally fair. However, the Board believes that the policy announced by the Government can be implemented in a manner which attempts to recognize and balance the interests of the petrochemical and allied industries, the oil and gas industry, the Government's commitment to both industries, and the overall public interest.

The Board continues of the view that any special ethane policy should limit Government and regulatory intervention to only that which is necessary to ensure the public interest. To the extent possible the policy should also permit development decisions to be governed by commercial interests of the affected parties and resource values to be determined by the marketplace. The Board believes that both industries would see such an effort by the Government in a positive manner.

The Board is not aware of any system which would accomplish the objectives of the Government as set out in its policy statement without, to some extent, intervening in industry decision-making processes respecting the installation of ethane recovery facilities. It nevertheless believes that wherever reasonably possible, the implementation of the policy should be in a manner which minimizes intervention. This objective should be pursued even if it means modifying certain aspects of the policy as described in the August statement. Also, in the Board's view, any policy adopted should not remain in place indefinitely. Additionally, if at any time the key players in the matter can find common ground with respect to elements of the policy or its implementation, the Government should be prepared to change or cancel any system that may be created through the subject inquiry, this report, and subsequent Government action.

In summary, and having regard for the prevailing situation respecting ethane removal at field facilities upstream of straddle plants, the Board sees "a policy" as a temporary necessity to resolve an existing dispute between two industries of great importance to the province. It believes "the policy" enunciated by the Government can be made to work in a reasonably fair manner until the situation shifts to one where it is no longer needed.

4.2 Issues

The principal issues the Board must deal with in implementing the Government's directive are set out in the Minister's letter to the Board dated 21 August 1987. As indicated previously, some participants in the

inquiry suggested the policy itself should be at issue. The Board, however, stated that the scope would be limited to the specific matters set out by the Minister and other relevant matters respecting implementation of the policy.

In addressing these issues, essentially all of the participants used as a basis for their positions, their own interpretations of any specific commitments that may have been made by the Government to the Project.

In the 21 August 1987 policy statement the Government "...reaffirms its policy to ensure that ethane will be available for petrochemical use in Alberta". It also establishes a policy of ensuring that sufficient ethane, the so-called threshold volume, will continue to be available to the petrochemical industry. Since "the Project" is the only existing ethane-based petrochemical industry in the province, it is clear that the Government considers it does have a commitment to ensure ethane is available to the Project.

What is not clear is whether the commitment exists because of undertakings given by the Government when the Project was being initiated and whether such undertakings related to specific volumes or defined the time period over which the ethane would be available. The Board therefore believes a review of the relevant documents is a logical and necessary starting point from which to consider and provide advice on the implementation of the Government's policy.

Consequently, the first issue which will be addressed is

- whether or not the documents relating to the initiation of the Project reflect specific ethane volume or time-period commitments by the Government to the Project.

The further issues related to the details of implementing the policy are as follows:

- the determination of the ethane facilities which should be affected by or be part of this policy;

- the principles that should be used in determining the threshold volumes and the actual volumes thereby determined;

- the determination of the procedures for requiring and the mechanism for ensuring reinjection or supply of ethane to the straddle plant system;

- procedures that should be used for the expedient regulatory processing of applications for field ethane extraction facilities;

- the existing and potential efficiency of ethane extraction at the straddle plants, the investment required to enhance extraction and potential linkages with threshold volumes;
- any legislative changes required to implement the policy; and
- any other relevant matters.

5 SPECIFIC COMMITMENTS BY THE GOVERNMENT RESPECTING THE AVAILABILITY OF ETHANE TO THE ALBERTA ETHANE/ ETHYLENE PETROCHEMICAL PROJECT

In addressing the matter of commitments by the Government to the Project it is important to make clear that the Board recognizes the overall commitment of the Government to the upgrading of resources within the province. This includes the very high level of upgrading including derivative manufacturing which takes place because of the existence of an Alberta petrochemical industry. The Board agrees with essentially all of the participants that such upgrading is in the province's best interest and is deserving of support. The issue being addressed in this section relates to the existence or otherwise of specific volume or time-period commitments respecting the assurance of long-term ethane feedstock for the Project.

Much of the discussion respecting commitments made by the Government to the Project related to the so-called "Dowling letters" exchanged between the proponents of the Project and The Honourable R. W. Dowling, then Minister of Business Development and Tourism, in September 1975 and April and May 1976. (Copies of these letters are included in Appendix 1B.) Reference was also made to the exchange of letters between the proponents and the Honourable H. Planche, then Minister of Economic Development, in December 1985. (These letters are included in Appendix 1C.) There was also much discussion regarding the Government policy statement dated 21 August 1987. All of these documents are included in Appendix 1. No other documents were filed by any of the participants at the inquiry that address this subject.

The 17 September 1975 letter to Mr. Dowling sets forth a series of intentions and undertakings by the proponents of the Project and requests certain commitments from the Government. The undertakings included the expansion or construction of straddle plants to remove ethane and of transportation and storage facilities to move the ethane to petrochemical markets within and beyond Alberta. There was a clear undertaking to build the first ethylene plant by a particular date, and reference is made to a second ethylene plant to be scheduled for completion as soon as practical after the first plant. The letter to Mr. Dowling also indicates "Additional ethylene plants timed to the additional requirements of the Alberta petrochemical industry, will be planned to consume the balance of the ethane supply...". The letter makes it clear that some ethane and ethylene would be marketed outside the province and describes conditions and undertakings related to the marketing, both within and beyond the provincial boundaries.

The letter requests confirmation by the Government relating to

(a) a 10-year commitment to take any necessary action to maintain the economic competitiveness of the ethylene produced by the Project if the price of gas within Alberta were to exceed the British thermal unit (Btu) parity with Canadian crude oil at the Toronto City Gate,

(b) the availability of adequate water supplies within reasonable distance of the ethylene plant sites, and

(c) the extraction of ethane on reasonable terms from the gas now leaving Alberta.

The Minister's 19 September 1975 response stated "Based on the undertakings and intentions expressed in your letter, the Government approves the Project subject to your company's complying with all of the applicable provincial statutes and regulations, and obtaining the necessary approvals from provincial regulatory bodies." It also confirms the Government's position respecting the three matters, the first two of which do not, in the Board's judgement, bear substantially on the subject being dealt with in this report.

In dealing with the third matter, Mr. Dowling's letter stated

"(c) The Government will take the appropriate steps to ensure that the ethane may be extracted on reasonable terms from the gas streams now leaving Alberta."

The petrochemical and straddle plant participants pointed to the references in the proponents' letter to two ethylene plants, possible additional plants, and the marketing of ethane and ethylene outside the province. They suggested that the Government's approval of the project, which was described in some detail in the original letter, coupled with clause (c) of the Dowling letter, could be translated to a specific commitment in terms of volumes of ethane. Their position generally was that Government approval of the Project meant a long-term commitment of sufficient volumes of ethane for the needs of the two ethylene plants and the marketing component, the latter to be satisfied until the third ethylene plant was built. They stated that clause (c) ensured, among other things, that producers would not be allowed to remove ethane upstream of the straddle plants, thus reducing ethane concentration and volumes available to the Project and jeopardizing its economic competitiveness.

On the other hand, the gas producers generally supported the view that clause (c) of Mr. Dowling's letter related to the need for the Project to make suitable arrangements with those owning the gas streams leaving the province and not to the extraction of ethane at field plants upstream of straddle plants. Several suggested that such a possibility was not

seriously contemplated in the mid-1970s by the Project. Their general view was that even if clause (c) did relate to "upstreaming", nothing in the Dowling letters would make the commitments specific in terms of volumes or the time period for which the commitment might apply.

The Board has carefully reviewed the Dowling letters and all other documents, having regard for the interpretations put forward at the inquiry. It has also had regard for its knowledge of the circumstances and views respecting the development of the Project and activity in all energy sectors that prevailed in Alberta and elsewhere in the mid-1970s when the letters were written. On the basis of its assessment, the Board is not convinced that clause (c) of the Minister's letter was intended to relate to the possible impact of upstreaming. In any case the Board does not believe that the Government's conditioned approval of the Project and the undertaking set out in clause (c) were intended to be a specific commitment of volumes of ethane to supply the three possible ethylene plants and the marketing component, even though they were referred to in the letters from the Project. Similarly, in the Board's view, Government approval of the cost of service arrangements would not necessarily mean a commitment that volumes of ethane would remain available to supply all of the facilities to which the cost of service arrangements apply.

The Project proponents in an April 1976 letter to Mr. Dowling set out amendments to their undertakings and sought clarification respecting the Government's position on one aspect of removal of gas from the province. Mr. Dowling's May 1976 response agrees with the amendments and the proponents' understanding of the gas removal matter, but does not alter the Board's view regarding the absence of a Government commitment for specific volumes of ethane. Similarly, the Board sees the exchange of correspondence in December 1985 only as a confirmation that Mr. Planche had no objections to certain changes to the earlier marketing undertakings by the Project. There is nothing in this correspondence to suggest to the Board a commitment to ensure specific volumes of ethane would be available for ex-Alberta marketing.

The Board's conclusion that the previously-mentioned documents were not intended to include a specific volume or term commitment is, in its judgement, consistent with the 21 August 1987 policy statement and the request of the Board to advise the Minister on details of implementation. Had the earlier documents been considered as commitments for specific volumes for specific time periods, it is unlikely the Government would have requested the Board's advice regarding the principles to be used in determining the threshold volumes. The Board does believe, however, that the Government may have given proponents of the Project the impression that it would generally assist them if their viability was threatened. The Board believes that the implementation of the proposed ethane policy is a mechanism for reinforcing that intent.

Having concluded that the documents do not give quantifiable direction on the specifics of the commitment to the Project, the Board believes it should rely on the direction given it in legislation as the basis for its considerations. This means the various matters referred to the Board by the Minister will be assessed from an overall Alberta public interest point of view.

Clearly an active growing petrochemical industry upgrading the province's energy resources will benefit the public interest, and likewise will a vibrant oil and gas industry which optimizes recovery of oil through EOR projects. The Board believes the existence of a competitive market for ethane would also serve the public interest and notes that the Government's policy is intended, in part, "...to maintain a functioning market in ethane wherein both the petroleum and petrochemical industry will have access to adequate and competitive sources of ethane supply...". A further element of the public interest, in the Board's view, would be a system where decisions to upgrade existing or construct new ethane extraction plants would be made on a "commercial basis" (subject to normal regulatory controls), and where impacts of various decisions on others would be dealt with through negotiation and appropriate agreements.

The above-mentioned elements of the public interest, and all others, must be considered by the Board in formulating its advice to the Government.

Although this section of the report is intended to deal with any specific commitments the Government may have made to the Project, the Board believes it appropriate to comment on one additional matter. This is that the Board itself has at no time made a commitment to the Project that removal of ethane upstream of its facilities would not be allowed. To the contrary, it alerted Project participants as early as 1976 in ERCB Decision 76-2 respecting the Ellerslie straddle plant application that upstreaming might occur. The following passage is taken from page 12 of that report.

"A lower than projected ethane recovery is also possible having regard for the Board's position that an approval of the applied-for facilities would not preclude the subsequent approval by the Board and the installation of ethane recovery facilities in field locations upstream of the plant. Such possibility is, in the Board's view, a business risk which the applicant would have to contend with."

Statements of this nature were repeated in several decisions of the Board over the years since 1976.

6 THE DETERMINATION OF THE ETHANE FACILITIES WHICH SHOULD BE AFFECTED BY OR BE PART OF THIS POLICY

6.1 Views of the Participants

6.1.1 Petrochemical Project

AGEC, the Ethylene Derivative Industry (EDI), and Empress/Ellerslie Straddle Plant Owners (SPO) submitted that the existing ethylene manufacturing facilities, AGE I and II, should be protected in terms of required ethane feedstock and in addition, AGE III should be protected when it is built.

All downstream participants stated that ethane marketing is an integral part of the Project and volumes for that purpose should be protected by the policy.

Project participants also indicated that the existing straddle system capacity should be recognized in establishing the policy. In addition, these participants argued that ethane extraction capacity added to the straddle plant system by the construction of new plants or improvement in the recovery efficiency should be recognized and protected.

With respect to field facilities, the Project indicated that the existing field plants within their existing licence limitations should be exempt from the policy. These plants are already in place with approved capacity, recovery factor, and sources of natural gas, and therefore should not be subject to the supply or reinjection of ethane into the gas stream to maintain the threshold volume. However, all new field plants which would move lean gas into the provincial gas collection system should be subject to the policy.

Those downstream participants who addressed the non-upstreaming field plants stated that these plants should be exempt from the policy but only during any period that lean residue gas from these plants does not enter the provincial gas collection system and thus not affect the amount of ethane available at the straddle plants.

With respect to the duration of protection provided by the policy, AGEC indicated it should last for the duration of the particular facility or, as a minimum, the contract life which is 20 years. SPO and ANG stated that there should not be an expiry date on the protection policy. ANG, however, indicated that a periodic review of the policy should be required.

6.1.2 Gas Producers

There was general agreement among the gas producers that non-upstreaming field plants, both existing and new, should be exempt from the policy and that, if there must be a policy, all new upstreaming plants should be subject to it.

The Ethane Owners Group (EOG) recommended that the policy, if it were adopted, apply to all existing and new field plants except those involving gas cycling, but be limited to a maximum period of 5 years and limited to meet the need of the AGE I and II plants only. It indicated that all AGEC ethane supply facilities including straddle plants, transportation, storage, injection, removal, and treating facilities would be affected by the policy.

The Independent Petroleum Association of Canada (IPAC) supported EOG in recommending exclusion from the policy of any facilities pertaining to ethane and ethylene removal from the province. Other gas producers did not make specific recommendations respecting downstream facilities except that there was general agreement that the policy should not protect the ethane supply for debottlenecking or expansions of AGE I and II or a third ethylene plant.

Opinion was divided, however, respecting existing upstreaming plants. EOG indicated that if its recommended threshold volume were accepted, the need to exempt any field facilities from the policy could be avoided by using the royalty share of production from all field ethane facilities, existing or new, to meet the threshold volume. One member of EOG, Chevron, specifically advocated grandfathering existing plants if compulsory transfers of ethane became necessary to meet threshold deficiencies. The latter would occur only if royalty ethane and freely negotiated ethane sales between producers and AGEC proved to be inadequate. Amoco Canada Petroleum Company Ltd. (Amoco) and IPAC asked that existing upstreaming plants be grandfathered and hence be exempt from having to reinject or supply ethane to the straddle plant system because they were constructed without knowledge of the policy.

6.2 Findings and Recommendations of the Board

This issue as set out in the policy statement refers to the facilities "...which should be affected by or be part of this policy." It is important to note that if the policy proceeds and for at least the period of its existence, all ethane- or ethylene-related facilities in the province will likely "be affected", either directly or indirectly. For this reason the Board is focusing its attention on those facilities that will directly be part of the policy or its administration.

Such facilities fall into two categories. One is the downstream facilities that produce or consume ethane and which need be considered in setting the appropriate threshold volume. The other is the upstream field plants which would be required to operate in a manner that ensures the downstream availability of the threshold volume.

As is the case with all of the issues set out in the policy statement, the Board believes it must have regard for the overall public interest in determining what facilities should be part of the policy. Of paramount

importance in this regard is a philosophy that facilities which have passed regulatory tests, have been approved, and are constructed or under construction should not have terms of the approval arbitrarily changed unless the public interest demands such changes. Investments related to existing facilities were made in the face of many risks but preferably they should not include possible impacts of a new policy such as that of the Government respecting ethane. On the other hand, once the policy is in place, decisions to invest capital in future expansions of existing facilities or the construction of new ones will be made with full knowledge of the Government's policy and intentions and the related risks.

Having this approach in mind, the Board believes that the downstream facilities that should play the key role in terms of the policy are AGEC's two existing ethylene plants. The existing derivative plants and other markets being supplied with the ethylene from those two plants will thus be affected by the policy. Also, the straddle plants and field plants whose ethane is currently contracted to AGEC will clearly be affected. The same is true, to varying degrees, for a number of other existing facilities such as the Cochin Pipeline, the AEGS, and ethane storage facilities.

Upstream facilities that should be part of the policy are those specific field plants that may be built in future and would be required to ensure that the threshold volume of ethane is available to downstream users. For the reasons expressed earlier, the Board believes that only field plants approved and built following the announcement of the policy should be part of it. To elaborate, it is sometimes necessary to retroactively apply new rules or regulations to existing energy facilities for conservation, safety, or environment reasons. However, the Board sees no compelling reason in this case to impose additional requirements on existing approvals.

There are frequently situations where changes to an approval for an existing plant are initiated by an approval-holder to increase plant capacity or allow processing of gas from new sources. Where this occurs and the changes are significant in the view of the Board, the ethane production from the expansion or new source of gas reserves should be made subject to the policy, unless the operator demonstrates that such was unreasonable or impractical.

The Board is of the view that plants, whether existing or new, whose residue gas is not available for reprocessing by the straddle plant system should not be a part of this policy, at least for as long as that mode of operation prevails.

7 THE PRINCIPLES THAT SHOULD BE USED IN DETERMINING THE THRESHOLD VOLUMES AND THE ACTUAL VOLUMES THEREBY DETERMINED

7.1 Views of the Participants

7.1.1 Petrochemical Project

Most downstream participants submitted that in the Dowling letters, the Government made a commitment to the Project to provide sufficient ethane on reasonable terms for ethylene manufacturing in the province. They held that principles in determining the threshold volume should therefore consider this commitment. They suggested that the key criteria in determining the threshold level is a stable long-term ethane supply and price for the petrochemical industry to maintain its economic competitiveness.

AGEC, EDI, and SPO indicated that the threshold volume should be set at a level where the requirements of AGE I and II at their debottlenecked capacity are met. It should also meet the requirements of the previously-approved third ethylene plant when that plant is built. ANG, however, indicated that the threshold volume should be flexible but designed to meet the petrochemical needs. SPO argued that the threshold volume should be set equivalent to the existing capacity of their plants to extract ethane and that further upstreaming should not be allowed.

Except for ANG who did not make any comment, all downstream participants also argued that the ethane marketing component of the project should be provided for in the threshold volume until the third ethylene plant is commissioned. Further, they recommended that the threshold volume should include provision for the Cochin Pipeline buffer requirement for shipments of ethylene through that pipeline.

The downstream participants tied their definition of threshold volume to straddle plant output rather than inlet ethane available and indicated that the threshold output volume should be increased in future to recognize any expansion to the straddle system either through addition of new plants or increases in efficiency of the existing facilities.

AGEC recommended that the threshold output volume be set initially at 21.5×10^3 m^3/d (135×10^3 bbl/d) and later, when AGE III is commissioned, be increased to 23.9×10^3 m^3/d (150×10^3 bbl/d). Except for ANG, the downstream interests argued that the threshold volume should remain fixed and not be related to swings in the levels of usage by the Project.

7.1.2 Gas Producers

According to EOG's interpretation of the Dowling letters, no specific ethane supply volume commitment was ever made to the two existing ethylene plants by the Alberta Government. Notwithstanding this, and though it contended that the threshold volume should be set at zero, EOG stated a preparedness to accept a threshold volume applicable for 5 years equal to the ethane requirements of AGE I and II prior to debottlenecking. This would amount to some 11.9×10^3 m^3/d (75×10^3 bbl/d), subject to certain adjustments.

Chevron pointed out that if the Government interprets a commitment in the Dowling letters, then that commitment should be limited to the Project as envisaged at that time, namely to the AGE I and II plants only. Chevron determined this to be about 11.8×10^3 m^3/d (74.4×10^3 bbl/d) of pure ethane.

EOG suggested that the threshold volume should be defined in terms of output at the straddle plants. Also there should be no protection in the threshold volume for expansion of ethylene manufacturing, for ethane marketing, or for expanded straddle plant capacity. EOG also argued there should be no increase in threshold volume to match plant efficiency improvements. However, IPAC and Shell considered it reasonable to include some sort of incentive in the administration of the threshold volume for such improvements.

IPAC proposed applying an efficiency differential factor to the current AGE I and II requirements less any exported ethylene volumes to determine the net threshold output volume. This factor would be calculated by finding the difference in residual ethane in the outlet streams between the older and the newer plants. Thus any efficiency improvements would lower this differential. In addition, it proposed a separate efficiency improvement factor which would allow increases in the threshold volume to a maximum equal to the current AGE I and II requirements.

Shell argued that incentives for efficiency improvement could be achieved by setting threshold volumes at the inlet of the straddle plants and permitting operators to implement improvements where commercial circumstances warranted such a move. Chevron also agreed that the threshold volume should be set at the straddle plant inlet and this would permit SPO to recover every cubic metre of ethane resulting from efficiency improvements.

Other areas of general agreement among the producers included estimating threshold and supply volumes on an annual basis, an overall maximum policy life of 5 years, and a return to a free market environment in both feedstock supply and product sales in as short a timeframe as possible. Shell suggested that the policy should phase out over a reasonable period of time. EOG emphasized that the policy should apply only to the

lowering of ethane content due to upstreaming, and that risks of reduced ethane availability caused by low gas flows or natural lower field ethane content should be assumed by the Project.

With respect to the size of the threshold output volume, there were some minor deviations from the positions given earlier regarding the AGE I and II plants. Chevron advocated the lesser of the design requirements or the actual ethane consumption of AGE I and II. EOG, Shell, and IPAC said the threshold output volume should not include volumes of ethane or ethane equivalent in the form of ethylene removed from the province.

7.2 Findings and Recommendations of the Board

The Board is of the view that the level at which the threshold volume is set will, to a large extent, determine the fundamental fairness of the policy. It was clear from the submissions to the inquiry that the Project favours a high threshold output volume, in the order of 21.5 to 23.9 x 10^3 m^3/d (135 to 150 x 10^3 bbl/d) to assure the ultimate feedstock requirements of an expanded Project and preserve the present feedstock cost structure. Gas producers, on the other hand, were largely in favour of a threshold output volume of zero but stated they were willing to compromise their perceived rights to the extent of maintaining for a limited period a threshold output volume of about 11.9 x 10^3 m^3/d (75 x 10^3 bbl/d).

From the Board's perspective, its decision regarding a threshold output volume to recommend to the Government must be based on the level that will best serve the public interest of Alberta. It would not appear to the Board to be in the public interest to adopt a threshold output volume that is so high that it would prohibit the construction of new field plants that might be used to supply ethane to the EOR market. Indeed, it would seem contrary to the policy itself to adopt such a threshold volume.

Similarly, however, it would not be in the public interest to allow the straddle system supply to be eroded by upstreaming to the extent that sufficient ethane would not be available to serve those petrochemical plants already approved and constructed. This, too, would be contrary, in the Board's view, to the intent of the policy.

7.2.1 Principles

The first principle the Board believes should be used in determining the threshold volume would be to ensure ethane feedstock to the existing ethylene plants for a reasonable time period. This in turn would ensure that ethylene is available for the existing derivative plants. All of these plants were invested in by companies that apparently believed they had some form of feedstock assurance. This is not so with the planned third ethylene plant because, although approved, actual construction

has not yet proceeded. The question of whether or not to recommend a threshold level which would provide for a third ethylene plant is an extremely important one. Evidence from the Project participants suggested that if AGE III were not provided for in the threshold volume, construction of that facility would not proceed. The gas producers, on the other hand, opposed inclusion of requirements for a third plant in the threshold volume and suggested that if the plant proceeded it should have to compete in the marketplace for its ethane feedstock supply. They also suggested that a third plant may well be sponsored by other than the Project participants.

As the Board sees it, the major advantage of including provision for AGE III in the threshold volume is that it would increase the likelihood that the plant would proceed in the near term as approved. A distinct disadvantage, however, would be pre-empting a supply of ethane to provide feedstock for a facility on which the investment funds had not yet been expended. To set aside volumes for a third plant would thus be contrary to the philosophy set out by the Board in Section 6.2 that facilities approved and constructed or under construction prior to the date of the policy announcement are those which require special recognition as part of the policy, while those facilities for which investments have not yet been made should not be given special treatment. It would also be contrary to the objective of the policy that it should minimize regulatory intervention in what should normally be a commercial decision.

Additionally, the Board is not convinced that a third ethane-based ethylene plant could not proceed in Alberta at some future time if it is not protected for in the threshold volume. In any case, the Board believes it would be in the public interest if the proponents of such a plant, regardless of whether they were part of the existing Project or not, negotiated with potential producers and contracted for the needed feedstock before the plant was built.

In further considering the question of a third plant, the Board does not believe that the policy was intended to do anything other than discharge earlier commitments which had been made or were understood to have been made to proponents of a project, which in turn resulted in investments being made. Since the third plant has not yet been built, there is an opportunity for the Government to clarify whether or not it wishes to make a commitment to that part of the Project. If one is made, whether it be in the form of a guaranteed supply or otherwise, the Board would see merit in that being negotiated and specifically agreed to before the further investment is made and the plant proceeds. If a form of support is so negotiated the Board also believes that it should be specifically identified as, and take the form of, Government support for the Project.

Having regard for all of these considerations and notwithstanding that exclusion of AGE III requirements from the threshold volume could very well represent a short-term setback to the petrochemical industry in the province, the Board has concluded that the potential requirements of the third plant should not be included in the threshold volume.

Some gas producers contended that the capacity of existing ethylene or derivative plants should not be provided for to the extent that the manufactured ethylene or derivatives are marketed outside Alberta. The Board believes that any significant petrochemical industry within Alberta will have to rely to considerable extent on markets outside the province. Consequently, the Board would not discount the volumes protected for the existing industry to reflect products marketed ex-Alberta.

There was considerable discussion at the inquiry about whether or not the ethane volumes used by the ethane marketing component of the Project should be included in the threshold volume. While the Board appreciates that income from sales of these volumes may help to cushion the cost structure of ethane feedstock and hence ethylene, it considers this to result primarily from the pricing arrangements and risk-sharing put in place for the benefit of the Project participants. The mere existence of such arrangements does not, by itself, justify recognition of them in setting the threshold volume. In fact, inclusion of such volumes in the threshold volume would probably ensure continuance of the pricing arrangements whether or not such would be in the Alberta public interest.

With respect to the inclusion or otherwise of the ethane marketing component in the threshold volume, the Board is mindful of the evidence suggesting that the Project could not have proceeded without the ethane marketing system. It is conjectural as to whether or not this is so. The Board believes that parts of the marketing system may have proceeded in any case. Its purpose would have been to market NGL other than ethane as well as any ethane recovered in Alberta and not needed for petrochemical purposes, the only real use at the time the Project was instituted.

Additionally, if the marketing component is included in the threshold volume, it would tend to concentrate ethane marketing in the hands of participants in the Project. This would dilute the chances of ensuring a "functioning" market for ethane, one of the objectives of the Government's policy. Also, it could interfere significantly with the ability of gas producers to supply the right type of hydrocarbon solvent for EOR purposes and to compete to sell ethane to those same markets pursued by the Project.

Therefore, as a further principle, the Board believes it would be unfair to include the ethane volumes of the Project marketing component in the threshold volume.

The evidence supplied at the inquiry shows that the development of the original Project contemplated the movement of ethylene to Dow in Sarnia. Ethane is the most appropriate buffer agent for preventing contamination of such shipments. To that extent the Board accepts as a principle that some volume of ethane for this purpose should be included in the threshold volume.

As a final but very important principle in recommending a threshold volume, the Board proposes that the threshold volume be established and administered as a volume of ethane available at the inlet to the straddle system. By recognizing the threshold volume in terms of inlet rather than output volumes, the introduction of straddle plant efficiency improvements is not jeopardized nor are poor efficiencies perpetuated.

As well, the Board believes that an inlet threshold volume will result in a simpler system to administer if reinjection from field plants becomes necessary. Also, a threshold volume appropriately based on the inlet to the straddle plants provides an assurance to the Project that enhancement in ethane recovery made at the straddle plants to produce additional ethane would not simply facilitate additional upstreaming. Indeed, such an approach could form the basis for the Project to ensure a portion of the feedstock requirements for a third ethylene plant by upgrading the recovery efficiencies at the straddle plants.

In administering a threshold volume based on the inlet to the straddle plants, it may be necessary to make adjustments with time, if additional upstreaming occurs and lowers the ethane content of the gas streams feeding the straddle plants so substantially that the recovery capability of the plants is appreciably reduced.

In summary, the Board believes the principles used in determining the threshold volumes should be as follows:

- inclusion of existing ethylene plants,
- exclusion of planned ethylene plants,
- exclusion of the marketing component,
- inclusion of an ethylene-buffering volume, and
- defining of the threshold volume at the inlet to the straddle plants.

7.2.2 Actual Threshold Volume

With respect to the actual threshold volume, the Board believes it would be reasonable to provide for the currently-approved capacity of AGEC's two ethylene plants, AGE I and AGE II, plus a judgement portion of the

capacity increment which would result from debottlenecking the plants. The approved capacity of these two plants is 13.2 x 10^3 m^3/d (83.3 x 10^3 bbl/d) of pure ethane. On the basis of evidence presented at the inquiry the Board believes the volume protected for should be 14.2 x 10^3 m^3/d (89.3 x 10^3 bbl/d).

A buffering requirement of 500 m^3/d (3 x 10^3 bbl/d) should also be included in the threshold. This is the estimated minimum needed for that purpose. The resulting total threshold output volume would thus be 14.7 x 10^3 m^3/d (92.3 x 10^3 bbl/d).

To convert this volume to a threshold volume at the straddle plant inlets, the Board deducted the contribution of Project field plants of about 950 m^3/d (6 x 10^3 bbl/d) and divided the remainder by a capacity-weighted straddle system average ethane recovery efficiency of about 0.7, reflecting an average recovery factor of 70 per cent. This gives an inlet threshold volume of approximately 19.6 x 10^3 m^3/d (123 x 10^3 bbl/d) of pure ethane which the Board recommends for use in implementing the Government's policy.

The 950 m^3/d (6 x 10^3 bbl/d) is the average ethane production over the past 4 years for the Waterton and Jumping Pound field plants which provide ethane to the Project. A review of relevant information suggests to the Board that these plants will be capable of delivering at least equivalent volumes for several years into the future. If production at these plants does decline below recent levels, the Board does not believe it would be appropriate to require other field plants to make up the underage as part of the threshold. It was therefore considered reasonable to subtract the 950 m^3/d from the required volumes before calculating the threshold volumes necessary in the inlets to the Project straddle plants.

The Board recognizes that a substantial reduction in the ethane content of gas feeding the straddle plants, particularly if coupled with a sizeable increase in gas flow rates, could result in a situation where the inlet volume of ethane could exceed 19.6 x 10^3 m^3/d (123 x 10^3 bbl/d), but the straddle plants as they now exist would not be capable of an average 70 per cent recovery. The evidence at the inquiry respecting this matter was not conclusive but the Board believes the ethane content could change significantly before this situation would prevail. Nevertheless, the system recommended for adoption should allow for an adjustment to the threshold volume if at some future date the Project can satisfy the Board that the average ethane content of the gas feeding the straddle plants has been reduced, by further upstreaming, so substantially that an adjustment is warranted.

7.2.3 Duration of Policy

The Board believes that it would be unreasonable and unnecessary in terms of meeting the intent of the policy to implement a threshold volume for an indefinite time period as suggested by many Project participants. It questions, however, whether the 5 years suggested by the gas producers would be a lengthy enough period.

The Board considers that a reasonable approach would be to match the term of the threshold volume with the terms of the industrial development permits for the two ethylene plants. These were each for 20 years. Although not the full lives of the plants, a 20-year term would mean each plant had an assured feedstock supply for a period which would typically be well beyond that planned for a payout of investment.

Such an approach would mean that the above threshold figure of 19.6 x 10^3 m^3/d (123 x 10^3 bbl/d) would be effective through the end of 1998 to coincide with the permit term for AGE I, after which it would decrease to 10.0 x 10^3 m^3/d (63 x 10^3 bbl/d) through the end of 2004. Commencing at 2005, the threshold volume would be nil.

It should be noted that the Board recommends the exclusion of the 500 m^3/d (3 x 10^3 bbl/d) buffering requirement after the permit term for the first ethylene plant has run out, the end of 1998. This is because the Board views the movement of ethylene out of the province as generally associated with the first ethylene plant rather than the second.

8 THE DETERMINATION OF THE PROCEDURES FOR REQUIRING AND THE MECHANISM FOR ENSURING REINJECTION OR SUPPLY OF ETHANE TO THE STRADDLE PLANT SYSTEM

8.1 Views of the Participants

8.1.1 Petrochemical Project

AGEC's position was that to ensure the supply of sufficient ethane to the straddle plant system, ethane should be reinjected by new field plants. The priority of obligation to restore the threshold volume, as recommended by AGEC, should be based on the "last built-first to reinject" principle. While SPO concurred with AGEC, ANG suggested that in case of shortfalls, new field plants should supply ethane to satisfy the threshold volume on a prorated basis reflecting field plant ethane volumes.

While other participants in the Project did not express any strong position on the priority of royalty ethane over producers' ethane for reinjection, AGEC submitted that royalty ethane from new plants should be taken before the producers' share from these plants.

Most participants in the Project indicated that the ethane required to maintain the threshold output volume could be reinjected or by-passed at field plants or could be supplied as volumes of ethane in kind directly to the Project. SPO noted that supply in kind by field plants would affect the straddle plant system cost structure unless the volume supplied is "deemed" to have been produced at the straddle plants. This would maintain the appropriate share of operating costs allocated to ethane production. AGEC concurred with the deeming proposal of SPO for volumes supplied in kind.

Both AGEC and SPO contended that the price of reinjected ethane or other liquids should be at the shrinkage cost (ie. the loss of Btu value in the gas sales market by removal of the heating value of the ethane). If the ethane is provided in kind, they said it should be priced at the shrinkage cost plus incremental cost of extraction at the straddle system. Other liquids (ie. propane and butanes) would be priced at their commodity value where supplied in kind.

AGEC recommended that legislative changes be put in place so that the Board could administer the maintenance of the threshold level. The Board would forecast ethane availability at the straddle system annually to assess the likelihood of having to order reinjection. The average annual threshold level would be converted to monthly entitlements based on the expected seasonal variation in gas throughputs. The Board would then monitor daily data to determine if reinjection were necessary. It would order reinjection of ethane by those ethane producers subject to the policy when there was a shortfall in the available ethane at the straddle system.

SPO and CEMJV concurred with the AGEC recommendations. EDI, on the other hand, suggested that after the policy is implemented through legislation, the Board should establish a joint task force to work out the details of the reinjection mechanics. ANG suggested that the Board direct a body or agency to administer the maintenance of the threshold level. It noted that NOVA or AEGS might be involved in monitoring threshold volumes through existing operational control systems.

8.1.2 Gas Producers

In order to restore a deficient threshold volume, EOG and IPAC agreed that the Project should first attempt to obtain the needed ethane volumes on the open market. If this were unsuccessful, then the Crown's royalty ethane from existing and new field plants should be either taken in kind or reinjected at the field plant gate for subsequent recovery at the straddle plants. Chevron and Shell, both EOG members, altered the order slightly and suggested that any deficit remaining after first using royalty ethane should be contracted for on the open market or alternatively, in Shell's opinion, prorated among all producers at each producer's contract price. Shell also emphasized that this should only occur after ethane exports from Alberta had been curtailed, straddle plants were not reinjecting or rejecting ethane[1], ethane storage facilities were being effectively utilized, and any physical constraints in the ethane gathering system had been removed.

Amoco regarded the priority of obligation for restoring the threshold volume slightly differently because of its position that existing field ethane extraction facilities should be grandfathered from the policy. In its view Crown royalty ethane and non-royalty production from new plants, respectively, should be used before Crown royalty volumes from existing field plants.

There was general agreement among the producers on the following points:

- The choice of whether to reinject ethane or supply ethane in kind should rest with the producer.

- The price to be paid for any ethane required to make up deficit threshold volumes must be based on its fair market value taking into account alternative uses and producers' contract prices.

- Advance notice for delivering deficient volumes was necessary. EOG and Norcen preferred a 90-day notice while Amoco said 60 days was sufficient.

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1 Rejecting ethane means deliberately not extracting as much of the available ethane as possible.

- The threshold volume should be administered on an annual basis.

Both EOG and Chevron detailed specific procedures for administering the threshold volume. In EOG's recommendations, AGEC would submit ethane supply and threshold volume information for the previous year's actual system performance, an estimate for the current year's system performance, and a forecast for the forthcoming year utilizing only Alberta gas flows. This submission would be open to public scrutiny and any complaint would initiate a hearing. The regulatory authority would rule on the matter and release a report detailing the current and forecast years' ethane supply and threshold volumes.

Only deficient volumes identified for the forecast year would be supplied. If no shortfall were forecast and then one occurred, the petrochemical industry would be required to obtain such deficiencies on normal commercial terms. In the event of a forecast deficiency and the necessity for supplying field royalty ethane to the petrochemical industry, the regulatory authority would first request field producers to offer ethane for sale at freely negotiated prices. If the offered volumes were insufficient to meet the shortfall, then producers would be required to deliver their prorata share of royalty ethane to satisfy the remaining deficiency. Additional volumes needed could be supplied from producer-owned ethane and credited against royalty obligations for other gas components. If still further volumes were required, then the price of this supply should be determined by taking into account the owner's contract and alternative uses to determine fair market value.

Chevron's procedures would apply only if the volume of royalty ethane available were insufficient to make up threshold volume shortfalls. The Project would provide a forecast of ethane supply to the Board prior to 1 October of each year for the subsequent year. Once the Board was satisfied the threshold volume could not be maintained and the Project had proved that shortfalls could not be met through system operation or efficiency improvements, it would convene a hearing.

Field operators would have the option of mutually deciding the best way to make up the shortfall. If they were unable to reach a consensus by 1 December, then the Board would devise a suitable method for transferring ethane at fair market value. Each owner would have the choice of reinjecting or supplying ethane in kind.

By 1 February following the forecast year, the Project would furnish the Board with a comparison of the actual ethane supply to the previous supply forecast including any volumes transferred from field plants because of the policy. If the actual supply exceeded the forecast supply, then any field-supplied ethane would have to be returned to the owners either in kind or at fair market value or carried forward to make up a potential shortfall in the current year. If the actual supply were less than forecast, then a reverse procedure would be followed.

8.2 Findings and Recommendations of the Board

In the Board's view, the procedure that will be set up to require the reinjection of field plant ethane to maintain the threshold supply to the Project is a critical part of the Government's policy. Indeed, as this part of the policy and its implementation will affect the day-to-day operation of private sector industrial facilities, the perception of the extent of the Government's involvement and of the fairness of the procedures put in place could have broad effects on decisions for future investment in Alberta by all industries.

In deciding on a procedure to recommend to the Government regarding the reinjection or supply of field plant ethane to maintain the threshold volume, the Board first addresses a number of underlying principles which it believes should form the basis of the procedures. It then sets out the recommended procedures.

8.2.1 Principles

The first, and in the Board's view the most important principle to be considered, is the manner in which a price is established for ethane that is required to maintain the threshold volume. The Board notes the reference in the Government's policy statement that the price to be paid for reinjected or supplied ethane would be "...the incremental cost of ethane extraction at the straddle plants". Having the benefit of evidence presented at the inquiry, the Board is very concerned about this aspect of the policy. Although it has focused its attention on the implementation of the policy as stated, it believes the Government should consider a possible alternative for pricing the ethane required to maintain the threshold volume.

In the Board's view, to set rules that require a seller to participate in a sale in which he has no input with respect to price would be perceived by essentially all parties to be fundamentally unfair. Additionally, the Board notes that a stated objective of the policy is to allow a "functioning market" for ethane in the province. The Board believes that the pricing arrangement proposed in the policy could be a deterrent to achieving a functioning market over the long term. Also, requiring the sale of ethane at any preset price would be contrary to the efforts being made, and considerable accomplishments already achieved, toward a deregulated oil and gas industry.

While it seems clear that the Government has intervened in the dispute over ethane extraction at the prompting of both the petrochemical and gas-producing industries, the Board believes that implementing the policy in a way that minimizes Government intervention should be an objective. While it appears that the policy is necessary at the present time to resolve the current impasse, and to provide some assurance to the Project

respecting availability of feedstock supply, the Board believes that the pricing arrangements proposed may be a case of unnecessary, or at least undesirable, regulation taking the place of commercial arrangements.

Therefore, as a principle that would alter the policy as announced, the Board recommends that the price to be paid for ethane that is required to be provided to the Project to maintain the threshold volume should be negotiated between buyer and seller, whether the seller is the Government and the ethane being transferred is Crown royalty ethane, or the seller is a field plant owner and the ethane is working-interest ethane.

The Board is cognizant that situations might arise in which the Project is unable to successfully negotiate price with sellers for the full volume necessary to make up a threshold volume deficit. Therefore, as a backup to the proposed negotiated price, the Board recommends that changes to the relevant legislation be made that would allow a fair price in the Alberta public interest to be set by a neutral third party. This party could be an appointed body such as the Public Utilities Board or the ERCB, or the price could be set through arbitration. (In the remainder of this report the reference will be to a neutral third party.) To ensure that the price would be in the overall public interest, which includes the interests of both the Alberta petrochemical and gas-producing industries, the Government may also want to give direction as to those factors which should be considered in setting a price.

The volume and source of the ethane to be transferred at the price set by the neutral third party would be determined by the ERCB as described in the procedures outlined later in this section.

The second principle relates to the question of which owners of ethane should be obligated by the policy to make ethane available to the Project to maintain the threshold level. As described in Section 6.2, the Board believes it would be in the public interest that only field plants built since the announcement of the Government's policy should be subject to the requirement to reinject ethane to maintain a threshold volume. All ethane production from field plants approved and constructed or under construction prior to the policy, subject to certain conditions described in Section 6.2 regarding expansions or processing of new gas, should be exempt from any reinjection requirement. This would include the Crown royalty volumes of ethane from such plants, although the Board understands that the Crown is entitled to take its royalty in kind whenever it desires, and dispose of it as it sees fit.

Another question relates to the priority use of the royalty versus the working-interest share of ethane produced at an affected field plant. The Board recommends that the first ethane that should be made available to maintain a threshold is the Crown royalty share of production from new field plants. This is suggested because the commitment made to the

Project was by the Government and because support of the petrochemical industry would be in the overall public interest. The royalty volumes, which belong to the overall public, would thus be serving an important general public interest function. Where the amount of royalty ethane available exceeds the required reinjection rate, the Government would consult with affected plant operators and decide from which plants the royalty ethane would be supplied. Where the total royalty volume available from all affected plants is not sufficient to satisfy the required reinjection rate, the deficit would have to be made up from working-interest ethane from the affected plants.

It should be noted that the above discussion addresses sellers that are obligated by the policy to make ethane available to the Project. In the functioning market which the policy hopes to work toward, there would be no restrictions on which sellers could make ethane available to the Project. All sources of supply would compete for available markets.

As a final principle related to determining how much reinjection should be required, the Board believes the Project should generally carry the total risk for reductions in ethane available at the straddle plants caused by reduced gas flows or reduced natural ethane content in the gas but not related to upstreaming. In this context, the Board's reference to reduced gas flows is relative to conditions in 1987.

Although this is set out as a principle, the Board does not expect that it would come into play in determining actual reinjection rates as outlined in the following procedures. Over the long term, the Board expects that gas flows to the straddle plants will increase and result in substantially more ethane, in the absence of further upstreaming, being available at those plants than in 1987.

8.2.2 Procedures to Be Used

As stated in Section 7.2, the Board recommends that initially an annual average threshold inlet volume of 19.6×10^3 m^3/d (123 bbl/d) be available in gas streams flowing to the straddle plants, in addition to the volumes available to the Project from the Jumping Pound and Waterton field plants.

Based on gas production data collected by the Board, and information presented at the inquiry respecting the ethane content of gas streams flowing to the straddle plants, the Board estimates that about 24.3×10^3 m^3/d (153×10^3 bbl/d) of ethane were available at the inlets to the straddle plants in 1987. This suggests that with 1987 conditions of gas flow and ethane content, an average 4.8×10^3 m^3/d (30×10^3 bbl/d) of ethane upstreaming could take place before field reinjection or delivery in kind would be required. If gas flows and ethane availability at the

straddle plants occur generally as forecast, there will be considerable room for additional upstreaming to take place before an obligation would be placed on field plants to meet the threshold volume.

Having regard for the above numbers and the potential ethane production projected in Section 3, the Board concludes that it is unlikely procedures established to require reinjection to maintain the threshold volume will be needed in the immediate future. For this reason, the Board describes in this section only general procedures that it believes would be functional. Pending the Government's decision respecting the Board's recommendations, the Board believes that further consultation with industry would be beneficial in establishing the details of the procedure that would accommodate the interests of all parties to the extent possible.

In the procedure proposed by the Board, the first thing to be established for a future year is whether or not field plant ethane is expected to be needed to restore the threshold volume and, if so, how much. The Board proposes that each year it would prepare an annual forecast of ethane available to the straddle plants and of ethane production at new field plants with input from affected parties. If the expected average rate of ethane available at the straddle plants over the year is greater than the recommended threshold volume, then the Board would advise that no field plant ethane is expected to be needed to restore the threshold. However, if the annual forecast suggests a shortfall of ethane available at the straddle plants, again based on a comparison of the expected average production rate over the year with the threshold level, then some amount of reinjection would be required during the year.

To illustrate how this might be done, a situation could occur in some future year, where the ethane available in gas flowing to the straddle plants has declined to 17.5 x 10^3 m^3/d (110 x 10^3 bbl/d). Because this is less than the threshold of 19.6 x 10^3 m^3/d (123 x 10^3 bbl/d), it suggests that some reinjection is required.

If we assume that new field plants are recovering 8.0 x 10^3 m^3/d (50 x 10^3 bbl/d), the shortfall would be attributed to upstreaming. The Board would thus issue an initial information directive that 2.1 x 10^3 m^3/d (13 x 10^3 bbl/d) of pure ethane equivalent must be supplied to the Project on average throughout the next year. It would also indicate the average royalty volumes expected from new field plants during the year. If we assume these would total 1.6 x 10^3 m^3/d (10 x 10^3 bbl/d), the information directive would indicate that the remainder of the shortfall must be supplied by working interest owners, ie. 0.5 x 10^3 m^3/d (3.1 x 10^3 bbl/d). On the other hand, if royalty ethane amounted to 2.1 x 10^3 m^3/d (13 x 10^3 bbl/d) or greater, the directive would indicate that no working-interest ethane was expected to be needed.

This information directive would be issued at least 90 days before the calendar year in question. The Project and field producers, including the Crown, would then be given 60 days to negotiate arrangements. It is only if the Project came back to the Board, in the last 30 days before the subject year, and stated it could not obtain the needed volumes, that the Board would issue a threshold volume make up directive. This would direct that the needed volumes which were not obtained through negotiation be made available by the Crown and working interest owners, as appropriate.

With the above-described procedure, the Project would in some instances obtain the required ethane volumes through negotiation, and in other instances as a result of a specific direction from the Board. In either case, the Board expects that negotiations between the buyer and the seller or sellers would establish pricing arrangements for the ethane. Other matters that would be subject to negotiation would include the price of other NGL, if necessary; whether the ethane is to be reinjected into residue gas at the field plant or supplied in kind, and if so at what location; periods of reinjection or delivery suitable to both the buyer and the seller; and the rates at which the ethane would be reinjected or otherwise made available.

Through this negotiation approach, and if the Government accepts the Board recommendation regarding price, the Board is hopeful that all or almost all of the ethane required to maintain the threshold volume could be acquired contractually. In the Board's view, this would be the most desirable way to accommodate the interests of buyer and seller.

As indicated previously, in situations where the Project is unable to secure the total amount of ethane needed to maintain the threshold, even after all royalty ethane from affected field plants is used, the Board would decide the reinjection rates needed at such plants.

To establish the reinjection rates needed, the Board proposes that it would simply divide the outstanding, uncontracted requirement by 365 days and set a fixed average daily rate for the year. Owners of affected field plants would first have the opportunity to decide among themselves which plants would supply the ethane so that disruption to their own markets would be minimized. Failing agreement among the field plant owners, the Board would prorate the reinjection requirement among the affected field plants based on each plant's net-of-royalty share of total upstream production.

In order to make adjustments to the ethane directed to be supplied to the Project, the Board believes that it would be reasonable to allow for a quarterly review of the ordered reinjection rate at the request of either the field plant owners or the Project. The Board would be prepared to adjust the reinjection requirement up or down if it were satisfied that a

discrepancy exists between the forecast ethane available and the actual ethane available. In making the adjustment it would carry forward any under- or over-reinjection that resulted from the inaccuracy of the forecast, and any under-reinjection that occurred because a plant operator did not reinject in accordance with the Board's direction. In addition, the adjustment would reflect the principle that delivery or reinjection of ethane would not be required to the extent that the Project is by-passing ethane around the straddle plant system and not recovering it.

Where arrangements for make-up of threshold volumes could not be negotiated and Board involvement is necessitated, some of the additional guidelines the Board would use are as follows:

- The choice of whether to reinject or deliver ethane in kind would rest with the operator of the field plant.

- Where ethane is delivered in kind, the volume would be adjusted downward to match that which would have been actually recovered at the straddle plant which processes the gas at its then-existing recovery efficiency.

- Where ethane is delivered in kind, the location for delivery must be at a suitable point on the Project's ethane gathering and storage system.

- There would be no requirement to provide propane or heavier hydrocarbons to the Project.

- Reinjection would be required daily at the average rate required for the year.

- The Project would be responsible for any shortfalls in threshold volume which occur because of reduced gas flows relative to 1987.

Where arrangements cannot be made regarding the price for ethane, as indicated earlier, the Board recommends the price be set by a neutral third party. The price set would be that judged to be fair and in the overall public interest. The Government may wish, in amending the legislation, to provide terms of reference for the setting of the price. Some of the matters this Board believes might be considered would include

- an attempt to balance the interests of the buyer and seller,

- the available markets for ethane,

- the value of ethane as a commodity,

- the heating value of ethane as part of the gas stream,
- the cost of extracting the ethane at the field plant and the incremental cost that would have been incurred had it been extracted at the straddle plant, and
- the cost of reinjection of the ethane back into the gas stream or delivering it in kind to an acceptable delivery point.

The Board has stated its opinion in several past decisions that it believed the resolution to the ethane extraction dispute that would best serve Alberta's public interest should be achieved through negotiation between field plant proponents and the Project. The Board continues to believe this to be the case and also that the proposed system, with the emphasis on negotiation between the buyer and seller, would provide the best way to implement the Government policy.

9 PROCEDURES THAT SHOULD BE USED FOR THE EXPEDIENT REGULATORY PROCESSING OF APPLICATIONS FOR FIELD ETHANE EXTRACTION FACILITIES

9.1 Views of the Participants

9.1.1 Petrochemical Project

The Project participants all suggested that applications for new field ethane extraction facilities (or expansions of existing plants) should be granted if the Alberta public interest is satisfied. They indicated that if their recommended threshold volume and procedures for making up deficiencies are accepted, there is no need for lengthy hearings. However, they recommended that notice of all applications should be given such that adversely affected parties could have a chance to intervene if necessary.

The Project argued that if the threshold level is not satisfactory, the approval of upstreaming facilities would affect the cost structure of the ethane production at the straddle plants and it would have to oppose future applications.

ANG recommended that the Board scrutinize the applications utilizing existing procedures with primary issues to consider being the amount of incremental ethane recovered, economic benefit to Alberta, and avoiding duplication of facilities.

9.1.2 Gas Producers

EOG suggested that approvals of upstream ethane extraction facilities could be made more routine by dispensing with the public hearing process when there were no contentious issues relating to environmental, safety, or conservation aspects of the specific project. In its view, such applications should be considered by the Board in the same manner as any other gas processing application. To support its position it referenced the Administrative Procedures Act R.S.A. 1980 where, in its interpretation, section 6 does not make a public hearing mandatory and section 4(a) permits a regulatory authority to determine the evidence relevant to an application. Evidence pertaining to the impact of upstreaming on the Project would be irrelevant once the public interest was determined by the setting of a threshold volume.

Chevron, on the other hand, interpreted sections 3 through 7 of this Act as appearing to make it impossible for the Board to refuse to hold a hearing if an affected party insisted on one. In order to overcome this perceived problem and thus to expedite application processing procedures, Chevron viewed as necessary changes in legislation to effectively suspend a party's right to a hearing under the Administrative Procedures Act and the Energy Resources Conservation Act. In addition, Chevron suggested

that were the Board to treat ethane extraction applications as "technical applications" as intended in the Oil and Gas Conservation Act and Regulations, the problem of lengthy hearings would not arise and the approval process would be automatically accelerated. Chevron used the term "technical applications" to mean dealing only with the limited issues of location, conservation, and environmental matters as they pertain to a specific facility application and the issue of orderly, economic, and efficient development as it pertains to a specific geographic area.

IPAC stated that it was not suggesting anyone be denied the right to a hearing, but that the long, protracted, adversarial hearings of the past relating to ethane supply/demand requirements could be avoided by setting a reasonable threshold volume and thus limiting the main issues to capacity design and dedication of ethane.

Both Shell and Norcen reiterated that policy implementation should avoid the need for most hearings, especially long adversarial ones, and emphasized the desirability to consider ethane extraction facility applications on the same basis as other gas processing applications. Shell suggested that the Board should specifically use legislation or procedural direction to limit the scope of future applications once the policy is implemented. In particular such applications should not consider province-wide or export ethane supply/demand comparisons or straddle plant/field plant efficiency comparisons in future.

9.2 Findings and Recommendations of the Board

The Board notes that the policy statement anticipates implementation of the policy whereby field plants can proceed with ethane extraction subject only to

- more expeditious regulatory approval, and

- the condition that the field plants may be required to reinject or supply ethane to the straddle plant system.

This section deals only with more expeditious regulatory approvals.

Section 29 of the Energy Resources Conservation Act states that the Board, in deciding on an application, must provide an opportunity to be heard to any party which could be adversely affected by approval of the application. This clause of the Act does not identify nor restrict the type of adverse impacts that must be considered by the Board. In practice, an ethane-recovery processing scheme has been subject to the conservation and environment requirements specified in ERCB and Alberta Environment Acts and Regulations; and such a scheme has been subject to to the scrutiny and objection of any party which perceives it would be

adversely impacted. This practice has led to the protracted application-handling process of the past 7 or so years, and it is desirable that this process be made more straightforward and less onerous on all parties.

The Board believes that the intent of the policy is to enable the Board to handle applications for ethane extraction in much the same manner it handles all other schemes to process gas. That is, after the Board is satisfied that the conservation, social, and environment requirements of the scheme are met, the scheme is generally in the public interest; and given that any approval would be subject to the ethane policy, the Board would expeditiously issue its approval of the scheme. The Board is prepared to adopt such an approach. In doing so, however, it recognizes that after an approval is issued, a party believing it would be adversely affected by the scheme could then apply to the Board for a hearing under section 43 of the Energy Resources Conservation Act. The Board would have to hear the matter or specifically rule that, since the approval was in accord with the ethane policy, the party making the application would not be affected by the scheme. A similar position, although not specifically stated, would have been taken in the original issuance of the approval without notice or hearing.

If, in practice, it turns out that the "expeditious approval" approach is not working as intended, the Government may wish to consider changes to the relevant legislation.

10 THE EXISTING AND POTENTIAL EFFICIENCY OF ETHANE EXTRACTION AT THE STRADDLE PLANTS, THE INVESTMENT REQUIRED TO ENHANCE EXTRACTION, AND POTENTIAL LINKAGE WITH THE THRESHOLD VOLUME

10.1 Views of the Participants

10.1.1 Petrochemical Project

SPO suggested that the concentration of ethane remaining in the residue gas stream exiting the plant is a better measure of the plant efficiency than a ratio of the ethane recovered to that entering the plant. They indicated that since the residue gas from the straddle plants contains, on the average, 1 per cent ethane, their recovery efficiency is as high as field plants which typically leave a similar ethane content in their residue gas.

SPO also argued that the straddle plant system is the most efficient way to recover ethane since it extracts ethane from all gas streams leaving the province, including those which have lower ethane content. The field plants, on the other hand, are typically built only at locations where gas with high liquids content can be processed.

SPO submitted a report by Fluor[1] which identified specific measures that could further increase ethane recovery at their plants. The most viable options for improving the recovery efficiency were identified to be at the Petro-Canada Empress plant and the Dome Empress I and Dome Empress II plants. The technology proposed by Fluor for the three plants would be the addition of low-temperature absorption sections to treat the expander outlet vapour streams. Under questioning, it acknowledged that no plant yet exists with the proposed process configuration that operates at the relatively lean ethane inlet concentrations that are experienced at the Empress plants.

SPO explained that for the Petro-Canada plant, an incremental ethane recovery of 1.41×10^3 m^3/d (8.89×10^3 bbl/d) could be achieved for an incremental capital investment estimated at \$44.8 million. For Dome Empress I, an incremental ethane recovery of 1.79×10^3 m^3/d (11.28×10^3 bbl/d) could be achieved for a capital investment estimated at \$37.8 million. For Dome Empress II, an incremental ethane recovery of 925 m^3/d (5.83×10^3 bbl/d) could be achieved for a capital investment estimated at \$14.3 million. SPO estimated the cost of service of the additional ethane at 11.57 to 31.26 $\$/m^3$ (exclusive of shrinkage cost).

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1 Study Report - Ethane Recovery Improvement Options - Empress Straddle Plants. Fluor Canada Ltd., November 1987 (Exhibit 7Z).

SPO said that the ethane content of residue gas from the above plants would be reduced by almost one-half of the existing level if the modifications were put in place. For the Petro-Canada plant, the ethane content of its residue gas would decrease from the current 1.4 mole per cent to 0.7 mole per cent, for the Dome Empress I plant it would decline to 0.9 mole per cent from 2 mole per cent, and for the Dome Empress II plant, the corresponding figures would be a reduction to 0.7 mole per cent from the current level of 1.2 mole per cent.

SPO argued that the threshold output volume level should be increased to recognize improvements of the recovery efficiency made at the straddle plants. ANG indicated that its straddle plant at Cochrane, which receives an ethane-rich stream, is operating at a very high efficiency level of 87 per cent. However, improvements could still be incorporated to increase the ethane recovery level to 94 per cent. This would result in an increased recovery of 590 m^3/d (3.70×10^3 bbl/d) with an investment estimated at $3.6 million.

ANG also emphasized that modifications (expansion, debottlenecking, efficiency improvements) should be encouraged through upward threshold volume output adjustments.

Shell also reviewed the costs of increasing the ethane recovery efficiency at its Waterton and Jumping Pound plants and concluded that under perceived economic conditions it would not be viable to expand or modify these plants.

EDI did not make specific comments on improvement in the recovery efficiency of the straddle plants. It indicated that these modifications are economic decisions.

Both AGEC and CEMJV indicated that they concur with the evidence presented by SPO. AGEC emphasized that the threshold output volume should recognize any incremental ethane recovered through improvement of straddle plant efficiencies.

10.1.2 Gas Producers

EOG viewed the straddle plant system to be, for the most part, inefficient and obsolete pointing to the significantly higher ethane extraction efficiencies achieved by the newer field plants. It saw no usefulness to the inquiry in the Handwerk Study[2] submitted by SPO nor any relevance to Issue 5 of the policy statement respecting the economically

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2 Effect of Ethane Upstreaming on Straddle Plant and Total Provincial Ethane Production, G. E. Handwerk (filed as part of Straddle Plant Owners Direct Evidence (Exhibit 7k)).

or technically achievable maximum ethane recovery. In its assessment of the inquiry evidence, EOG concluded that barrels of ethane not recovered in the field are not recovered at the straddle plants on anything near a one-for-one basis.

EOG testified that, in its opinion, the Fluor Study utilized inappropriate, outdated technology which overstated the costs. It believed it would be feasible using new technology to bring the ethane in the residue gas down to about the 0.6 per cent level at much lower unit costs. Hence, EOG saw significant scope for improving recovery efficiencies at the Empress plants and thereby expanding the ethane supply. It acknowledged, however, that it knew of no other system operating on a feed stream with as low ethane content as that at Empress.

IPAC pointed to the higher recoveries at the field plants. It also offered two potential efficiency definitions: one, the more common definition of per cent removed divided by per cent in the inlet stream, and the second, the percentage left in the residue gas. IPAC indicated that it preferred the second definition and that it believed technology was available to permit extraction efficiencies to less than 1 per cent in the residue stream.

With the exception of Shell and IPAC, there was agreement among producer interests that there should be no linkage between any increased efficiency and the threshold output volume. IPAC suggested adjusting the threshold volume by using an efficiency differential calculated on the basis of the difference in the per cent ethane left in the residual gas stream between older and newer plants times the net capacity threshold volume determined from AGE I and II design capacity requirements less exported ethylene/ethane. However, the threshold volume would never exceed the AGE I and II design capacity requirements. Shell favoured a lower threshold volume which would gradually phase out, thus encouraging increased recoveries at straddle plants and ultimately encouraging toll processing of producers' gas.

Chevron maintained that if implementation of the policy encouraged efficient ethane recovery, then there would always be a sufficient ethane supply; and steps to maintain a threshold output volume would never have to be put into effect.

IPAC and Shell noted that insufficient capacity in the western leg of the AEGS was already causing ethane to be rejected in plants connected to that leg. Increased capacity would have to be installed to allow increased ethane supplies to be available to the Project. On a similar note, EOG agreed that constraints in the Project's ethane gathering and storage system should be taken into account in determining the suitability of upstream injection to satisfy the threshold volume.

10.2 Findings and Recommendations of the Board

With respect to the straddle plant efficiency issues, the Board's primary objective in making its recommendations to the Government is that the policy be implemented in a way that does not inhibit or preclude future enhancement at the straddle plants that could further reduce the ethane content of the natural gas streams leaving the province. The Board believes such would be in the public interest so long as there are potential markets for the ethane that is recovered and its value is higher than its fuel value if left in the natural gas. In the Board's view, increased recovery of ethane in Alberta will be desirable for the foreseeable future.

The Board believes that its recommendation that the threshold volume be established as a volume available in the gas flowing into the straddle plants - a threshold inlet volume - accomplishes the above objective. By fixing the threshold as proposed, the Project is assured of a supply of ethane available to it which at the current straddle plant efficiencies is sufficient to meet the feedstock requirements of the two ethylene plants. The Board is also prepared to make adjustments to the threshold volume if new upstreaming lowers the ethane content such that the current efficiencies could not be achieved.

The Project can decide in the future whether or not to enhance the efficiency of the plants to recover more of the ethane available to it based on the usual commercial considerations, whether there is demand for the additional ethane that could be extracted, and whether its cost would be competitive with alternative supplies. Those investment decisions would not be at risk at least in terms of the threshold inlet volumes set by the ethane policy.

With respect to the potential ethane recovery efficiency that could be achieved at the straddle plants, the Board notes the evidence presented by SPO that suggested a number of process modifications that would reduce the ethane content of the residue gas streams from the current range of 1.0 to 1.5 per cent to a range of about 0.5 to 1.0 per cent. The evidence suggested that an additional amount of almost 4.8×10^3 m^3/d (30×10^3 bbl/d) of ethane could be extracted by the straddle plant system if the outlined efficiency enhancements were undertaken, although the amount of additional ethane could be less depending on the amount of further upstreaming that might occur. On the basis of the evidence submitted to the inquiry, the Board estimates that as much as two-thirds of the potential additional extraction or some 3.2×10^3 m^3/d (20×10^3 bbl/d) might be recoverable from the threshold inlet volume and therefore not affected by upstreaming. Such a volume could form part of the feedstock supply to a third ethylene plant.

The Board also expects that, under the proposed policy, the Project would actively negotiate with producers who may potentially upstream the straddle plants to avoid that prospect. The Board believes that under those conditions, significant additional volumes could continue to be dedicated to the Project.

11 ANY LEGISLATIVE CHANGES REQUIRED TO IMPLEMENT THE POLICY

11.1 Views of the Participants

11.1.1 Petrochemical Project

Project participants who commented on the necessary legislative changes recommended that changes be made to the Oil and Gas Conservation Act and Regulations to enable the Board to administer maintenance of the threshold volume level. Both AGEC and EDI made specific comments on the changes to the Oil and Gas Conservation Act and Regulations, in particular, section 26. AGEC also recommended that section 10 of the Oil and Gas Conservation Act be amended to add jurisdiction for the Board to make regulations

"(a.2) providing for the implementation, control and monitoring by the Board of any scheme which may have the effect of limiting the amount of gas products which may be extracted from gas, or which may necessitate the by-passing or reinjection of gas or gas products at gas processing facilities."

Its recommendation on section 26 (which requires Board approval of gas processing schemes) is to add the following:

"26.1 In approving any application under this subsection for the removal of any gas product or gas products from gas, the Board may make such approval conditional upon any terms and conditions that the Board may prescribe, including:

(a) a limitation as to the amount of a gas product or gas products which may be extracted from the gas,

(b) provisions for the by-pass or reinjection of gas, gas product or gas products as may be directed by the Board from time to time."

EDI recommended more detailed and extensive additions to section 26 which would give the Board specific authority to implement the ethane policy. These recommendations relate specifically to its suggestions of how the policy should be implemented.

11.1.2 Gas Producers

IPAC and Amoco made no comments respecting required legislative changes. There was general agreement among the others, however, that the Board does not currently have the authority to order reinjection or delivery of ethane to meet any threshold volume deficiencies. Hence, changes to the Energy Resources Conservation Act and the Oil and Gas Conservation Act would be necessary.

Chevron suggested that whatever the mechanism established, it should be quasi-judicial to ensure fairness to all affected producers. Both Shell and Norcen emphasized that any changes in legislation should not adversely affect ownership rights. Shell added that any legislated policy should rapidly devolve into a free-market-oriented approach. Norcen recommended that any changes should reflect concern for simplicity and efficiency of administration.

11.2 Findings and Recommendations of the Board

As noted in Section 9.2 of this report, implementation of the policy statement will result in two key changes for future field ethane extraction schemes. These changes would result in more expeditious regulatory approval and approval conditions that may require reinjection or supply of ethane to the straddle plant system.

It has been suggested by several of the inquiry participants that specific legislative provisions, some enabling and some restrictive in nature, will be necessary to accommodate the changes. The Board agrees that the changes which would flow from the Board's recommendations made earlier in this report will require a detailed review of, and possible revisions to, the applicable acts and regulations. The Board's views regarding expeditious processing of ethane applications are set out in Section 9.2 of this report. The following are its views respecting the inclusion of conditions in approvals which would require the reinjection or supply of ethane to the Project.

If the Board's recommendations for implementation of the ethane policy are adopted, approvals of new field plants whose residue gas is subsequently reprocessed by the straddle plant system would be subject to two ethane-related conditions.

The first condition would state that the scheme is subject to a call for ethane which may be made if the Board determines the threshold volume must be maintained by field plant ethane. The condition would state that the Crown ethane would first be subject to reinjection or supply to the Project, but that some or all of the working interest ethane may also be called for.

The second condition would state that the price for the ethane to be reinjected or otherwise supplied would be the subject of negotiation between the Project and, as applicable, the Crown and the field plant owners subject to the condition. The condition would state that failing agreement on the ethane price, the price would be set by a neutral third party operating under predetermined terms of reference. The latter would ensure that the price set would be that judged to be fair and in the overall public interest.

The Board believes that it may have the authority under the general powers provision, section 15 of the Energy Resources Conservation Act, to condition processing scheme approvals in the manner described above. However, to avoid potential problems it recommends that the Oil and Gas Conservation Act be amended to give it the specific power to so condition approvals.

Depending on the particular selection of the neutral third party, a further change to legislation would be required to give the party jurisdiction to set prices and also to spell out the matters to be considered in establishing prices.

The potential case of gas produced outside of Alberta but moved into Alberta for processing was raised at the inquiry. The Board believes that Alberta would have only limited jurisdiction over this gas, and recommends that it not be subject to the ethane policy. To try to make such gas subject to the policy could result in its being processed outside Alberta which could be contrary to the province's interest.

In its preliminary review of the necessary legislative changes, the Board has considered in a general manner whether the required legislative provisions would raise serious questions in such areas as free trade, deregulation, and the Constitution. The Government may wish to review these matters in greater detail.

12 ANY OTHER RELEVANT MATTERS

There was much discussion at the inquiry of a number of other ethane-related matters. These included views of various parties respecting matters such as proprietary rights of producers, Canada/U.S. trade, the importance of EOR, a free market versus a regulated market, and current cost-of-service contracts. The Board had appropriate regard for all of these matters in shaping its recommendations to the Government. It does not believe that there are any other matters which require specific comments.

13 SUMMARY OF RECOMMENDATIONS

The Board recommends to the Government that it implement the ethane policy in accordance with the following set of recommendations.

Facilities that should be part of policy

1. The threshold volume should make provision only for ethane to supply petrochemical plants which were approved and operating or under construction at the time of announcement of the policy.

2. Field plants extracting ethane which were approved and operating or under construction at the time the policy was announced should not be subject to the condition to supply ethane to support the threshold volume. If such plants undergo major expansion or if significant new reserves are connected to them, the expansion or new reserves should be made subject to such a condition.

3. New field plants extracting ethane should be subject to the condition to supply ethane to support the threshold volume except where they are not delivering lean residue gas to a stream which is subsequently processed by a straddle plant. For plants not delivering lean residue gas to the straddle plants, exemption from the policy condition would continue as long as they operate in that mode.

The setting of the threshold volume

4. The approximate debottlenecked capacity of the existing ethylene plants AGE I and II, 14.2×10^3 m^3/d (89.3×10^3 bbl/d) of pure ethane[1], should be provided for as part of the threshold volume. Planned expansions to existing ethylene facilities and new facilities such as AGE III should not be, because the necessary investments have not as yet been made.

5. The ethane marketing component of the Project should not be included in the threshold volume other than a minimum volume of 500 m^3/d (3×10^3 bbl/d) of pure ethane for use as a buffer to move ethylene batches through the Cochin Pipeline.

6. The threshold volume should be expressed on the basis of ethane at the inlet of the straddle plants, ie. threshold inlet volume. Such a system would be administratively less complex than threshold output volume and would encourage investments in upgrading of the straddle plants.

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1 Specification ethane is approximately 94 per cent ethane and therefore volumes expressed as specification ethane are some 6 per cent larger than those expressed as pure ethane.

7. The capacity of the existing ethylene plants and the required buffer volume, when adjusted for straddle plant extraction efficiencies, results in a threshold inlet volume at the Project straddle plants of 19.6×10^3 m^3/d (123×10^3 bbl/d) of pure ethane. This, in addition to the some 950 m^3/d (6×10^3 bbl/d) which is committed to the Project from field plants at Waterton and Jumping Pound, would provide the ethane necessary for feedstock for the two debottlenecked ethylene plants as well as for buffering ethylene batches in the Cochin Pipeline.

8. The protection for the two ethylene plants should be for the terms of their respective industrial development permits. Each of these was initially for 20 years. This would mean the full threshold inlet volume of 19.6×10^3 m^3/d (123×10^3 bbl/d) would be provided until the end of 1998. The protection for AGE I and the buffer would then expire, leaving a threshold inlet volume of 10×10^3 m^3/d (63×10^3 bbl/d) through to the end of the year 2004. Protection under the policy would be discontinued at that time.

Procedures for supplying ethane to the straddle plant system

9. The Government should reconsider the position put forward in the policy statement that the price to be paid for reinjected or supplied ethane would be the incremental cost of extracting the ethane at the straddle plants. As an alternative that would be more in the public interest, the price to be paid for such ethane should be negotiated between buyer and seller. The relevant legislation should be changed to assure that a fair price be set by a neutral third party in those situations where a price could not be negotiated.

10. For those plants which must provide ethane to the Project to maintain the threshold inlet volume, all of the Crown royalty ethane should be so provided before any freehold royalty ethane or working-interest ethane is subject to the requirement. Royalty ethane from those plants not subject to the requirement to supply the Project should not be affected by the policy. This would not preclude the Crown taking such royalty ethane in kind and providing it to the Project if it so desired.

11. The requirement to provide ethane to the Project should be based on an annual forecast made by the Board at least 90 days prior to the year in question. The forecast should recognize input from affected parties. The Board should advise as to whether it is expected that ethane would be needed to maintain the threshold inlet volume for the coming year and, if so, the quantities. Sixty days would then be provided for the Project, the producers, and the Crown to negotiate sales of the needed make-up volumes.

12. Provision of ethane to the Project would be ordered by the Board only if negotiations for make-up volumes failed. The directed supply would be on an average-day basis for the full year and would be subject to adjustment on a quarterly basis if necessary to reconcile differences between actual and forecast ethane availability.

13. Where provision of ethane to the Project is directed by the Board, it would be done in accordance with a set of guidelines which would be established by the Board and made known to all parties.

14. Affected field plants would be required to provide ethane to the Project to the extent that the shortfall in ethane resulted from upstreaming as opposed to reductions in gas flow at straddle plants.

Procedures to be used for expedient processing of applications

15. The Board would approve, without hearing or notice, any ethane extraction application if it were satisfied that conservation, social, and environment requirements were met, and if the scheme were in the public interest; and any approval would be in accordance with the ethane policy.

Extraction efficiencies at straddle plants

16. Expression of the threshold volume as an inlet to the straddle plants, as set out in item 6, would encourage the upgrading of recovery efficiencies at the straddle plants.

Necessary legislative changes

17. The relevant legislation should be changed to ensure that the Board has jurisdiction to condition processing scheme approvals to require that ethane be made available to maintain the threshold inlet volume, and that the price of such ethane be subject to negotiation, or failing agreement, be set by a neutral third party.

18. The relevant legislation will require amendment to establish the jurisdiction and terms of reference for an appropriate neutral third party to set prices for ethane supplied to the Project where a negotiated price could not be achieved.

19. Gas produced outside of Alberta, but processed within the province, should not be subject to the ethane policy.

DATED at Calgary, Alberta, on 11 April 1988.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Chairman

N. A. Strom, P.Eng.
Vice Chairman

F. J. Mink, P.Eng.
Board Member

APPENDIX 1A GOVERNMENT OF ALBERTA POLICY STATEMENT ON ETHANE

- Letter dated 21 August 1987 from The Honourable Dr. N. Webber, Minister of Energy.
- Policy Statement on Ethane.

RECEIVED AUG 21 1987

ENERGY

Office of the Minister

228 Legislature Building, Edmonton, Alberta, Canada T5K 2B6 403/427-3740

August 21, 1987

Mr. G.J. DeSorcy
Chairman
Energy Resources Conservation Board
640 - 5 Avenue S.W.
Calgary, Alberta
T2P 3G4

Dear Mr. DeSorcy:

The Government of Alberta has recently announced a policy with respect to ethane. A copy of the policy statement is attached.

The policy statement indicates that the Government intends to amend the legislation to require that approvals of upstream ethane plants be made subject to the condition that if ethane volumes at the straddle plants fall below certain 'threshold volumes', the upstream plants will be obliged to reinject ethane to the straddle plant system to maintain threshold volumes or to supply ethane at the incremental cost of extraction of the straddle plant system.

The Government requests that the Energy Resources Conservation Board include such conditions in all approvals of upstream ethane extraction facilities, but otherwise ensure expeditious processing of applications.

The statement indicates the need for further consultation with the industry and consideration of the policy, its implementation, and any amendments to the legislation required to implement the policy.

I am hereby requesting that the ERCB consider and report on the ethane policy, with particular reference to the following specific matters:

1. The determination of the ethane facilities which should be affected by or be part of this policy.

2. The principles that should be used in determining the threshold volumes and the actual volumes thereby determined.

. . . / 2

3. The determination of the procedures for requiring and the mechanism for ensuring re-injection or supply of ethane to the straddle plant system.

4. Procedures that should be used for the expedient regulatory processing of applications for field ethane extraction facilities.

5. The existing and potential efficiency of ethane extraction at the straddle plants, the investment required to enhance extraction and potential linkages with threshold volumes.

6. Any legislative changes required to implement the policy.

7. Any other relevant matters.

I look forward to a timely report on this matter because, as you are aware, there are currently a number of active applications to recover ethane at field plants. If possible, the report should be available by November 15, 1987. If this is not feasible, I would appreciate being kept informed as to when I may expect your report.

Sincerely,

Neil Webber

Neil Webber
Minister

Attachment

August 21, 1987

POLICY STATEMENT ON ETHANE

Over the last ten years a world-scale ethane based petrochemical industry has located and expanded in Alberta. Development of the industry represents a major success in terms of the Government's objectives of economic diversification and maximum upgrading of Alberta's resources within the Province. This development reflects the industry's recognition of the stable and supportive business environment in Alberta and the long-term, secure, market-priced supply of the essential petrochemical feedstocks.

The Alberta Government also recognizes the important economic contribution of the oil and gas industry to Alberta and the investments it has made in support of a major objective of the Alberta Government, the encouragement of optimal resource development. As part of this objective, Enhanced Oil Recovery (EOR) by hydrocarbon miscible floods has been specifically encouraged by incentives under section 4.2 of the Petroleum Royalty Regulation.

The feedstock of the existing ethylene-based petrochemical industry is ethane, principally extracted at "straddle plant" facilities located at Empress and Cochrane, Alberta. During the last decade, there has been increasing demand for field extraction of ethane to provide solvent for enhanced oil recovery and, potentially, to provide feedstock for petrochemical facilities. It has been stated that the construction of ethane extraction capacity upstream of the straddle plants, which removes ethane which would otherwise be available at the straddle plants, could affect the availability of adequate supplies of ethane at the straddle plants to meet current petrochemical obligations.

Applications to the Energy Resources Conservation Board (ERCB) to recover ethane at field plants upstream of the straddle plant system have resulted in numerous lengthy public hearings. As a result, the Government has received numerous representations from the petrochemical, gas-producing, straddle-plant and enhanced oil recovery industries to take some action to improve the situation.

The Alberta Government believes that sufficient ethane is and will be available in the province to meet foreseeable demand for ethane for both petrochemical feedstock and EOR solvent. However, continued upstreaming has the potential to jeopardize straddle plant ethane supply, especially during periods of low natural gas flows through the straddle plants.

Therefore, the Alberta Government is announcing measures to maintain a functioning market in ethane wherein both the petroleum and petrochemical industries will have access to adequate and competitive sources of ethane supply and the incentive for further development of ethane-related activity in the province.

The Alberta Government re-affirms its policy to ensure that ethane will be available for petrochemical use in Alberta. More specifically, the Government will take action to require the Energy Resources Conservation Board to include in further approvals of upstream ethane extraction facilities a condition that the upstream plants will be required to reinject or supply to the petrochemical industry, which depends on straddle plant ethane, sufficient ethane to maintain the "threshold volumes" required by the petrochemical industry.

If ethane availability at the straddle plants drops below the "threshold volumes", then the ERCB will direct upstream plants subject to the condition to reinject or supply (at the incremental cost of ethane extraction at the straddle plants) ethane to restore the threshold level.

In this manner, the petrochemical industry is assured that its straddle plant supply cannot fall below "threshold volumes". With this security of supply the petrochemical industry can proceed with investment in additional ethylene capacity and in enhancing ethane extraction efficiency at the straddle plants.

The policy also means that the petroleum industry can proceed with upstream ethane extraction, in addition to other non-upstreaming facilities, subject only to more expeditious regulatory approval by the ERCB and the condition that they may be required to reinject or provide ethane to the straddle plants. As a result of this policy such approvals

should become routine and not be subject to the major upstreaming hearings experienced between 1981 and 1986.

In order to address the administrative issue of levying royalty on ethane from field deep cut extraction plants, which is currently royalty liable, but for which there is no liquid royalty prescribed, the Alberta Government will introduce a royalty on liquid ethane. As with all royalties, the government may elect to take the royalty in kind.

The Alberta Government wishes to have further consultation with the industries affected concerning the policy and the procedures for implementing the policy.

For this reason the Alberta Government will request the ERCB to inquire into the following specific matters:

1. The determination of the ethane facilities which should be affected by or be part of this policy.

2. The principles that should be used in determining the threshold volumes and the actual volumes thereby determined.

3. The determination of the procedures for requiring and the mechanism for ensuring re-injection or supply of ethane to the straddle plant system.

4. Procedures that should be used for the expedient regulatory processing of applications for field ethane extraction facilities.

5. The existing and potential efficiency of ethane extraction at the straddle plants, the investment required to enhance extraction and potential linkages with threshold volumes.

6. Any legislative changes required to implement the policy.

7. Any other relevant matters.

APPENDIX 1B THE DOWLING LETTERS

- Letter dated 17 September 1975 from the Project proponents to The Honourable R. W. Dowling, Minister of Business Development and Tourism.
- Letter dated 19 September 1975 from The Honourable R. W. Dowling to the Project proponents.
- Letter dated 26 April 1976 from the Project proponents to The Honourable R. W. Dowling.
- Letter dated 11 May 1976 from The Honourable R. W. Dowling to the Project proponents.

DOW CHEMICAL OF CANADA, LIMITED
DOME PETROLEUM LIMITED
THE ALBERTA GAS ETHYLENE COMPANY LIMITED
THE ALBERTA GAS TRUNK LINE COMPANY LIMITED

September 17th, 1975.

Honourable R. W. Dowling,
Minister of Business Development
and Tourism,
228 Legislative Building,
Edmonton, Alberta.
T5K 2B6

Dear Sir:

The purpose of this letter is

(a) to set forth the intention and undertakings of The Alberta Gas Ethylene Company Limited (AGE), The Alberta Gas Trunk Line Company Limited (AGTL), Dow Chemical of Canada, Limited (Dow) and Dome Petroleum Limited (Dome); and

(b) to request certain commitments from the government of Alberta

all with respect to the development of the petrochemical project described in this letter.

Dome and AGE intend to negotiate for the expansion or the construction of the following straddle plants for the economic recovery of ethane:

Straddle Plant Location	Plant Owner	Ethane Volume Barrels Per Day (Approx.)
Empress	Dome/PanCanadian Petroleum Limited	30,000
Empress	Pacific Petroleums Ltd.	33,000

Cochrane	Alberta Natural Gas Co. Ltd.	27,000
Edmonton	Dome/Canadian Utilities Limited	20,000
	TOTAL	110,000

Should any of the Plant Owners be unwilling to proceed with an ethane extraction plant forthwith, then Dome and AGTL jointly will proceed with the design and construction of such ethane extraction plant and in such event will offer to the Alberta Energy Company (AEC) a one-third interest in such plant.

All of the said straddle plants will sell ethane on a cost of service basis. As used in this letter, the phrase "cost of service" will be calculated on a formula similar to the cost of service formula now used by The Alberta Gas Trunk Line Company Limited (AGTL) gas transmission system in Alberta. There will be a reasonable rate of return on the equitv based on a debt to equity ratio no more favourable to the owners of the facility than 75:25.

Income taxes will be calculated on a flow through basis for a minimum period of 5 years. Thereafter, allowance may be made for deferred taxes, including amortization over the remaining life of the facility of deferred taxes not provided for during the initial period of 5 years. Capital cost allowance will be taken in such a manner as to minimize the cost of the service with depreciable assets being written off on a straight-line basis at 5% per annum.

The interest rates to be used to establish the rates of return on rate base and to calculate the income tax components

of the cost of service will be the prevailing long term rates available to the owners of the facilities at the time of construction and at the time of any subsequent refinancing.

Dow and Dome undertake to sell at the market prices prevailing at the time of such sale the volumes of natural gas that are necessary to provide to TransCanada Pipelines Limited the BTU's removed below 1,000 BTU/Cubic Foot at Empress as as result of the ethane extraction referred to above.

Dome and AGTL undertake to construct and operate on the said cost of service basis within Alberta the necessary ethane gathering and storage facilities to carry ethane from the said straddle plants to ethylene plants or the Cochin pipeline as the case may be. Dome and AGTL undertake to offer to AEC an interest of not less than one-third of their interest in the said gathering and storage facilities on terms no less favourable than those on which they hold their interests.

AGE undertakes to build the first ethylene plant having a capacity of 1.2 billion pounds per year using the said ethane as a feedstock with an estimated completion date of the said plant on or about July 1, 1978 and undertakes to sell ethylene on the said cost of service basis. AGE also undertakes to build and operate on the said cost of service basis a distribution and storage system to carry the ethylene to petrochemical plants using ethylene as a feedstock or to the Cochin pipeline as the case may be. A second ethylene plant based on ethane will be scheduled for completion as

soon as practicable after the first ethylene plant. If AGE does not so proceed with the second ethylene plant, Dome and Dow shall have the right to construct the second plant. The cost of ethylene from all ethane based ethylene plants shall be equal.

Dow and Dome undertake to construct the Cochin pipeline which will carry ethane or ethylene from Alberta to markets in other places in Canada or the United States. Dow and Dome undertake to offer the owners of the ethane extraction plants in proportion to each plant's production capabilities an interest of up to 25% in the said pipeline on terms no less favourable than the interests held by Dow and Dome. In addition, Dow and Dome will offer to AEC an interest of up to 25% in the said pipeline upon the same terms.

Dome will purchase from AGE for delivery at the western terminus of the Cochin pipeline ethane which is surplus to the requirements of the ethylene plants. The price of ethane delivered to AGE's ethylene plants and to the western terminus of the Cochin pipeline will be an average price based on the prices of all extracted ethane as defined above plus an average cost of service of ethane gathering and storage. Ethane sold to Dome for removal from Alberta will be transported in the Cochin pipeline and sold to Columbia LNG Corporation (Columbia) at the commodity price under the Dome/Columbia agreement or to other fuel markets outside of Alberta. The net cumulative income from the sale of ethane

to Columbia or other fuel markets outside of Alberta shall be distributed as follows:

- 50% to the owners of the Cochin pipeline in proportion to their respective share of the ethane shipping agreements
- 20% to owners of the ethane extraction plants in proportion to their respective share of ethane production
- 30% to AGE to be applied against its cost of ethane for ethylene manufacture.

Dow undertakes to purchase from the first ethylene plant 700 million pounds per year of ethylene to be used in Alberta as follows:

(a) 350 million pounds per year to manufacture 700 million pounds per year of vinyl chloride monomer. Dow will build additional chlorine-caustic plant capacity to provide the chlorine required to make the vinyl chloride monomer. Dow proposes to locate the vinyl chloride monomer plant and the chlorine-caustic plant at Fort Saskatchewan.

(b) 350 million pounds per year in a styrene plant to be built by Dow and an ethylene oxide plant to be built by Dow.

Dow also undertakes to purchase 500 million pounds per year of ethylene from AGE from the first ethylene plant for use in the manufacture of additional derivatives within Alberta, for use in Eastern Canada or sale by Dow to export markets in the U.S.A.

Dow undertakes to close down its ethylene manufacturing plant in Sarnia, which has the capacity to produce 110 million pounds per year of ethylene as soon as at least 110 million pounds per year of ethylene is available to Dow from shipments through the Cochin pipeline.

With respect to ethylene produced from the second ethane based ethylene plant Dow will have the first option to use up to 300 million pounds per year of ethylene for manufacture of derivatives in Alberta. Other persons and Dow may on or before January 1, 1977 elect to commit on a firm take or pay basis to take said ethylene for use in the manufacture of derivatives within Alberta providing AGE or Dow and Dome have given the Government of Alberta substantial undertakings by January 1, 1977 that construction of the second ethylene plant will commence within six months after January 1, 1977. In the event that such undertakings are not given by AGE or Dow and Dome by January 1, 1977, then the date for commitment by other persons to take ethylene will be extended for a further period of 90 days after such undertakings are given. To the extent that, after deliveries for said commitments by other persons or Dow there remains ethylene from the second ethylene plant, Dow and Dome will commit that said remainder will be removed from Alberta through Cochin pipeline. Dow will take delivery of up to 300 million pounds per year of said remainder in Eastern Canada, provided that the total ethylene from the first and second ethylene plants taken by Dow to Eastern Canada does not exceed 500 million pounds per year, and the balance of the remainder will be sold by Dow

and Dome to export markets in the U.S.A. The Government or AGE may upon two years notice given after the start of production from the second ethylene plant withdraw for use in the manufacture of derivatives within Alberta 100 million pounds per year of ethylene and the Government or AGE may upon 4 years notice given after the start of production from the second ethylene plant withdraw for use in the manufacture of derivatives within Alberta an additional 200 million pounds per year of ethylene, from that portion of the ethylene or part thereof going to export markets in the U.S.A. The Government or AGE may upon 5 years' notice to Dow, given at any time after 5 years from start of production from the second ethylene plant, withdraw for use in the manufacture of derivatives within Alberta any remaining portion of the ethylene or part thereof going to export markets in the U.S.A.

Additional ethylene plants timed to the additional requirements of the Alberta petrochemical industry, will be planned to consume the balance of the ethane supply and replace the volumes of ethylene withdrawn as above from export to U.S.A. markets. Any of the companies shall have the right to cause the manufacture of ethylene from the said ethane within the Province of Alberta if this should prove to be necessary to ensure that ethylene is available to protect existing export movements. The ethylene from such plants shall be available for use in Alberta upon the same terms and conditions as the ethylene from the second plant.

Dow undertakes not to use in Eastern Canada more than 500 million pounds per year of ethylene produced in Alberta.

Dow and AGTL or AGE with other possible owners undertake to construct and operate a plant to produce approximately 100 million gallons per year of benzene, using as feedstock approximately 30,000 Bbl per day of condensate. Benzene will be sold to Dow for use in the manufacture of styrene. Upon the request of the Government of Alberta, Dow and AGTL (or AGE) undertake to construct a world-scale liquid cracker using as feedstock raffinate from the said benzene plant, supplemented by additional condensate or other suitable material, or alternatively to make the raffinate available for this use by others on the said cost of service basis or some other mutually agreed to basis. If Dow and AGTL or AGE build the said world scale cracker, the products therefrom will be made available to users within Alberta on a cost of service basis or some other mutually agreed to basis.

All of the undertakings given herein by the various companies are subject to the conditions that the Companies are able to make the necessary financial arrangements to proceed with the proposed project and are able to obtain the necessary regulatory approvals.

The Companies are also giving the undertakings herein upon the understanding that the Government of Alberta may create a body which may acquire ownership of the ethane or ethylene and which will in turn sell it at the Government's acquisition cost (which acquisition cost will not be higher than the cost which would have been payable had the Government body not purchased ethane or ethylene) to the companies

which under this proposal would be using or transporting ethane or ethylene.

The companies intend to use the maximum practicable Canadian engineering, design, fabrication and construction content in the proposed Alberta facilities.

The undertakings are also being given upon the understanding that it is the policy of the Government of Alberta:

(a) to ensure, except with respect to ethylene used by Dow in Eastern Canada to the extent of 500 million pounds per year herein referred to and to ethane used in fuel markets outside of Alberta, that ethane and ethylene are not shipped out of Alberta for use as petrochemical feedstocks in such a way as to impede or hinder the development of the petrochemical industry within Alberta; and

(b) that the Government of Alberta's first priority is to have ethane extracted from the natural gas streams leaving Alberta upgraded to ethylene and thereafter further upgraded by petrochemical derivative plants, and its second priority is the conversion of ethane to ethylene for shipment out of Alberta, and its third priority is the removal of ethane from the natural gas streams and shipped out of Alberta for non-petrochemical use.

The companies jointly request confirmation from the Government of Alberta that:

(a) It is the Government's policy to have the wellhead price of natural gas within the Province of Alberta based on a price at BTU parity with Canadian produced crude oil at the Toronto City Gate less natural gas transportation cost back to the wellhead in Alberta. The Government of Alberta recognizes that the economic competitiveness of the project is at this time primarily based on that policy. In the event that the price of Alberta natural gas goes above the said parity, the Government of Alberta, for a period of ten years from the date of start-up of the first ethylene plant, will take such action as may be required to maintain the economic competitiveness of ethylene produced by A.G.E. in Alberta.

(b) The Government will ensure that there is available within a reasonable distance from Government approved plant sites an adequate water supply for the projects described in this letter but the Government will not be responsible for the cost of transporting the water to any plant site.

(c) The Government will take the appropriate steps to ensure that the ethane may be extracted on reasonable terms from the gas streams now leaving Alberta.

In addition, Dow requests confirmation from the Government of Alberta that in the event the government provides grants or subsidies to other users of ethylene produced from ethane, that Dow will be given equal treatment.

Yours truly,

THE ALBERTA GAS TRUNK LINE COMPANY LIMITED

Per: ____________________

THE ALBERTA GAS ETHYLENE COMPANY LIMITED

Per: ____________________

DOW CHEMICAL OF CANADA, LIMITED

Per: ____________________

DOME PETROLEUM LIMITED

Per: ____________________

BUSINESS DEVELOPMENT
AND TOURISM

Office of
the Minister

403/427-3162

228 Legislative Building
Edmonton, Alberta, Canada
T5K 2B6

September 19, 1975

DOW CHEMICAL OF CANADA, LIMITED
DOME PETROLEUM LIMITED
THE ALBERTA GAS ETHYLENE COMPANY LIMITED
THE ALBERTA GAS TRUNK LINE COMPANY LIMITED

Dear Sirs:

We acknowledge receipt of your letter of September 17, 1975 describing your proposed petrochemical project. Based on the undertakings and intentions expressed in your letter, the Government approves the project subject to your company's complying with all of the applicable Provincial statutes and regulations, and obtaining the necessary approvals from Provincial regulatory bodies.

In accordance with your request, the Government of Alberta confirms that:

(a) It is the Government's policy to have the wellhead price of natural gas within the Province of Alberta based on a price at BTU parity with Canadian produced crude oil at the Toronto City Gate less natural gas transportation cost back to the wellhead in Alberta. The Government of Alberta recognizes that the economic competitiveness of the project is at this time primarily based on that policy. In the event that the price of Alberta natural gas goes above the said parity, the Government of Alberta, for a period of ten years from the date of start-up of the first ethylene plant, will take such action as may be required to maintain the economic competitiveness of ethylene produced by A.G.E. in Alberta.

(b) The Government will ensure that there is available within a reasonable distance from Government approved plant sites an adequate water supply for the projects described in this letter but the Government will not be responsible for the cost of transporting the water to any plant site.

(c) The Government will take the appropriate steps to ensure that the ethane may be extracted on reasonable terms from the gas streams now leaving Alberta.

.... 2

DOW CHEMICAL OF CANADA, LIMITED
DOME PETROLEUM LIMITED
THE ALBERTA GAS ETHYLENE COMPANY LIMITED
THE ALBERTA GAS TRUNK LINE COMPANY LIMITED

Sept. 19, 1975

In addition, the Government of Alberta confirms that in the event it provides grants or subsidies to other users of ethylene produced from ethane, that Dow Chemical of Canada Limited will be given equal treatment.

Sincerely,

R. W. Dowling

DOW CHEMICAL OF CANADA, LIMITED
DOME PETROLEUM LIMITED
THE ALBERTA GAS ETHYLENE COMPANY LTD.
THE ALBERTA GAS TRUNK LINE COMPANY LIMITED

April 26, 1976

Honorable R. W. Dowling
Minister of Business Development
and Tourism
228 Legislative Building
EDMONTON, Alberta
T5K 2B6

Dear Sir:

Pursuant to our discussions of March 25, 1976, the purpose of this letter is to amend the intentions, undertakings and commitments set forth in our letter to you of September 17, 1975, and your letter to us of September 19, 1975. These amendments involve changes in wording of the September 17, 1975 letter.

1. The requirements and sources of ethane are set out in the table at the bottom of page 1 and top of page 2 of the letter of September 17, 1975. We would add at the bottom of this table the following:

   "The initial requirements of ethane will be 75,000 barrels per day and will be produced from some or all of the plants referred to in the above table as determined by Dome and AGE. Additional capacity to produce ethane in excess of this initial requirement will be constructed as the project may require."

2. Add the following sentence to the first complete paragraph on page 3 (line 10):

   "Dow and Dome understand that the Government of Alberta, for this specific project, will authorize the removal from Alberta of such additional volumes of gas as would be necessary to compensate for BTU'S removed below 1,000 BTU'S per cubic foot subject only to such additional volumes of gas being found surplus to Alberta's present and future requirements by the Energy Resources Conservation Board."

. . . 2

3. Change the date "July 1, 1978" in the fourth line of the last paragraph on page 3 to:

   "December 31, 1978."

   Also, in the fifth line of the last paragraph on page 3 delete:

   "AGE also undertakes to"

   and substitute therefor the following:

   "AGE and Dow also undertake that one or both of them will...".

4. Add the following sentence immediately after the sentence which ends in the first line of page 4:

   "The ethane required for the second ethylene plant will be derived from an expansion of the ethane straddle plants above the initial capacity of approximately 75,000 barrels per day from the sources described above or any other available sources. In the event that there is a shortfall of ethane after construction of the additional facilities, the shortfall volume will be made available by a reduction of the amount of ethane being shipped through the Cochin pipeline."

5. Revise the first sentence in subparagraph (a) on page 5 to read:

   "400 to 450 million pounds per year to manufacture 700 million pounds per year of vinyl chloride monomer and 150 to 300 million pounds per year of ethylene dichloride."

6. Add the following words at the end of second sentence in subparagraph (a) on page 5:

   "and ethylene dichloride".

7. Amend subparagraph (b) on page 5 to read as follows:

   "(b) 300 million pounds per year in an ethylene oxide plant to be built by Dow".

8. Delete first full paragraph on page 8 which reads as follows:

   "Dow and AGTL or AGE with other possible owners undertake to construct and operate a plant to produce approximately 100 million gallons per year of benzene, using a feedstock approximately 30,000 Bbl per day of condensate. Benzene will be sold to Dow for use in the manufacture of styrene. Upon the request of the Government of Alberta, Dow and AGTL (or AGE) undertake to construct a world-scale liquid cracker using as feedstock raffinate from the said benzene plant, supplemented by additional condensate of other suitable material, or alternatively to make the raffinate available for this use by others on the said cost of service basis or some other mutually agreed to basis. If Dow and AGTL or AGE build the said world-scale cracker, the products therefrom will be made available to users within Alberta on a cost of service basis or some other mutually agreed to basis".

. . . 3

Would you please confirm your agreement to the above.

Yours truly,

THE ALBERTA GAS TRUNK LINE COMPANY LIMITED

PER: ____________________

THE ALBERTA GAS ETHYLENE COMPANY LTD.

PER: ____________________

DOW CHEMICAL OF CANADA, LIMITED

PER: ____________________

DOME PETROLEUM LIMITED

PER: ____________________

BUSINESS DEVELOPMENT
AND TOURISM

Office of
the Minister

403/427-3162

228 Legislative Building
Edmonton, Alberta, Canada
T5K 2B6

May 11, 1976

Dow Chemical of Canada Limited
Dome Petroleum Limited
The Alberta Gas Ethylene Company Limited
The Alberta Gas Trunk Line Company Limited

Gentlemen:

We acknowledge receipt of your letter of April 26, 1976. The Government of Alberta agrees with the amendments to the letter agreement of September 17, 1975, as set out in your letter of April 26, 1976, and the understanding of Dow and Dome with respect to the authorization by the Government of the removal of additional surplus volumes of gas to compensate for BTU reduction caused by ethane recovery in Alberta.

Yours truly,

R. W. Dowling

APPENDIX 1C THE PLANCHE LETTERS

- Letter dated 16 December 1985 from the Project proponents to The Honourable H. Planche, Minister of Economic Development.

- Letter dated 30 December 1985 from The Honourable H. Planche to the Project proponents.

DOME PETROLEUM LIMITED

DOW CHEMICAL CANADA INC.

NOVA, AN ALBERTA CORPORATION

THE ALBERTA GAS ETHYLENE COMPANY LTD.

December 16, 1985

The Honourable H. Planche
Minister, Economic Development
Government of Alberta
Room 320, Legislative Building
EDMONTON, AB

Dear Sir:

Re: Alberta Ethane/Ethylene Petrochemical Project
Letter of Intention & Undertakings dated September 17, 1975

This letter is further to communications amongst representatives of our Companies and officials of the Department of Economic Development respecting the impending loss of the Columbia LNG Corporation contract for the sale of project ethane, the major impact this will have on the operation and viability of the Cochin pipeline system and the resultant effect this will have on the Alberta ethylene petrochemical project and Alberta natural gas producer interests.

Our Companies have been seeking alternative ethane markets to replace, at least in part, the Columbia LNG Corporation contract and minimize the impact of the loss of this market on the Cochin pipeline system and the Alberta ethylene petrochemical project. In seeking alternative markets, we have established the following criteria as conditions for any sale to a petrochemical market outside Alberta:

1. any such sale will proceed only if it will impose no material negative impact to the existing or prospective Alberta ethylene or ethylene derivative industries;

2. any such sale will only be of a short to medium term duration and will be subject to recall for use in any installed Alberta petrochemical facility;

3. any such sale will be to supply only existing capacity and will not be to supply expansions or new capacity additions; and

4. any such sale will be concluded only where viable alternatives are available to the potential purchaser and where the terms of any such sale are competitive with such alternatives, and provided further that the price to the potential purchaser shall not be less than the cost of ethane purchased from the project's extraction system.

We believe these criteria are consistent with the intentions and undertakings of our Companies as expressed in the September 17, 1975 letter. We would appreciate your early response to this initiative being undertaken by the project to respond to the current urgent and difficult circumstances of the Cochin pipeline system.

Yours truly,

DOME PETROLEUM LIMITED

Per: ______________________

DOW CHEMICAL CANADA INC.

Per: ______________________

NOVA, AN ALBERTA CORPORATION

Per: ______________________

THE ALBERTA GAS ETHYLENE COMPANY LTD.

Per: ______________________

REB/el
85081

Office of the Minister

ECONOMIC DEVELOPMENT

320 Legislature Building, Edmonton, Alberta, Canada T5K 2B6 403/427-2134

30 Dec 85

Dome Petroleum Limited
Dow Chemical Canada Inc.
Nova, An Alberta Corporation
The Alberta Gas Ethylene Company Ltd.

Dear Sirs:

This is in response to your letter of December 16, 1985 requesting my comments on your proposal to sell ethane into petrochemical markets outside of Alberta.

Firstly, it is understood that the undertakings contained in a September 17, 1975 letter from Dow Chemical of Canada Ltd., Dome Petroleum Ltd., the Alberta Gas Ethylene Co. Ltd., and the Alberta Gas Trunk Line Company Ltd. to the then Minister of Business Development and Tourism, The Honourable R.W. Dowling, continue in force.

Secondly, to the extent that the parties to these undertakings are now proposing to sell ethane for use as petrochemical feedstock under the terms indicated in your December 16th letter to me, it is my perception that such sales conform with the original undertakings and, as such, I have no objection to such sales taking place.

Yours truly,

Hugh Planche
Minister

APPENDIX 2 LIST OF INQUIRY PARTICIPANTS

Principals and Representatives	Witnesses
The Alberta Gas Ethylene Company Ltd. H. D. Williamson F. R. Foran, Q.C.	J. H. Butler, P.Eng. Dr. J. E. Feick D. J. McConaghy C. L. Mort (of C. L. Mort Consulting Inc.) R. L. Pierce Dr. W. A. Langford (of NOVA, An Alberta Corporation)
The Ethylene Derivative Industry: Union Carbide Ethylene Oxide/Glycol Company (Union Carbide) Dow Chemical Canada Inc. (Dow) C-I-L Inc. (C-I-L) Celanese Canada Inc. (Celanese) Novacor Chemicals Ltd. (Novacor) R. A. Neufeld	D. Center Dr. T. R. Jones (both of Union Carbide) W. McCagherty G. Telmer (both of Dow) G. Clarke (of C-I-L) Dr. I. Brownlie (of Celanese) D. Ferris, P.Eng. (of Novacor)
The Straddle Plant Owners: Dome Petroleum Limited (Dome) PanCanadian Petroleum Limited (PanCanadian) Petro-Canada Inc. (Petro-Canada) D. M. Wolcott and Associates Ltd. D. A. Holgate	D. G. Ramsden-Wood (of Dome) W. C. Reinwart (of PanCanadian) T. H. Skupa, P.Eng. (of Petro-Canada) G. E. Handwerk, P.Eng. (independent consultant) F. J. VanGinhoven, P.Eng R. A. Raidt, Professional Engineer registered in the State of Texas (both of Fluor Canada Ltd.)
Alberta Natural Gas Company Ltd M. A. Putnam, Q.C.	W. S. Chmilar, P.Eng. D. A. Sharp, P.Eng. J. A. Smith

Principles and Representatives	Witnesses
Cochin Ethane Marketing Joint Venture W. J. Hope-Ross	D. G. Ramsden-Wood W. R. Weaver (both of Dome)
The Ethane Owners Group: Amerada Mineral Corporation of Canada Ltd., Anderson Exploration Ltd. Canadian Hunter Exploration Ltd. (Cdn. Hunter) Canterra Energy Ltd. Chevron Canada Resources Limited (Chevron) Conoco Canada Limited Esso Resources Canada Limited (Esso) Gulf Canada Resources Limited (Gulf) Home Oil Company Limited Mobil Oil Canada, Ltd. (Mobil) Norcen Energy Resources Limited Shell Canada Limited Sulpetro Limited (Sulpetro) Texaco Canada Resources (Texaco) Unocal Canada Limited D. G. Hart, Q.C. R. C. Muir D. G. Davies	M. Bregazzi (of Gulf) C. J. Caffrey, P.Eng. (of Mobil) J. A. Dillabough, P.Eng. (of Cdn. Hunter) N. H. Eggen, P.Eng. (of Texaco) G. M. Engbloom, P.Eng. (of Confer Consulting Limited) B. C. Fleming (of Cdn. Hunter) Dr. K. E. Godard, P.Eng. (of Chevron) R. V. Gooden, P.Eng. (of Texaco) Dr. D. J. Hawkins, P.Eng. (of Hycarb Engineering Ltd.) D. J. Henry (of Esso) W. D. Onn (independent consultant) Dr. J. P. Sutherland (of J. P. Sutherland and Associates) J. D. Wilkinson, Professional Engineer registered in the State of Texas (of Ortloff Engineers, Ltd.) R. J. Zaharko, P.Eng. (of Sulpetro)
Amoco Canada Petroleum Company Ltd. D. G. Arnason, P.Eng. R. Wingfield, P.Eng.	R. B. Arnold, P.Eng.
Anderson Exploration Ltd. A. H. Williamson, P.Eng.	
Canadian Hunter Exploration Ltd. J. F. Mackie	

Principles and Representatives	Witnesses
Canterra Energy Ltd. R. C. Muir	
Chevron Canada Resources Limited B. K. O'Ferrall R. A. Pashelka	R. A. Park, P.Eng. Dr. K. E. Godard, P.Eng. W. H. Armstrong, P.Eng. R. M. Shaunessy, P.Eng.
Conoco Canada Limited R. E. Pelzer B. E. Schellenberg, P.Eng.	
Esso Resources Canada Limited D. G. Hart, Q.C.	
Gulf Canada Resources Limited D. G. Davies	
Home Oil Company Limited C. A. Keck B. Peterson	
Mobil Oil Canada, Ltd. D. Bews	
Norcen Energy Resources Limited D. G. Davies	
Poco Petroleums Ltd. P. J. McIntyre B. Brander	
Shell Canada Limited R. W. Riegert	R. P. Cej, P.Eng. J.W.F. Klein, P.Eng. J. M. Wakim S. G. McDonald, P.Eng.
Sulpetro Limited P. H. Forrest R. J. Zaharko, P.Eng.	
Texaco Canada Resources J. I. Parker	
Independent Petroleum Association of Canada A. S. Hollingsworth J. Snider	R. B. Hillary H. M. Sorensen, P.Eng.

Principles and Representatives	Witnesses
ProGas Limited N. Boutillier L. Clarke	
Western Gas Marketing Limited D. McLean	
Pan-Alberta Gas Ltd. D. Dawson	
City of Red Deer A. Scott	A. Scott
Energy Resources Conservation Board staff M. J. Bruni G. Habib B. C. Hubbard, P.Eng. Dr. F. Rahnama W. J. Schnitzler, P.Eng.	

APPENDIX 3 SUMMARY OF VIEWS OF INQUIRY PARTICIPANTS

This summary is provided as a convenience to readers of the report. It is a general overview of the positions of the participants in the inquiry on the major issues and sub-issues. It is not intended to be an exhaustive review nor to be totally complete. Note that the Board's views, findings, and recommendations contained in this report are based on the evidence presented at the inquiry and not on this summary.

Also for the reader's convenience the abbreviations used in this appendix are reproduced below:

AEGS	Alberta Ethane Gathering System
AGE I and II	Alberta Gas Ethylene's First and Second Ethylene Plants
AGE III	Alberta Gas Ethylene's Proposed Third Ethylene Plant
AGEC	Alberta Gas Ethylene Company Ltd.
Amoco	Amoco Canada Petroleum Company Ltd.
ANG	Alberta Natural Gas Company Ltd
bbl	barrels
bbl/d	barrels per day
CEMJV	Cochin Ethane Marketing Joint Venture
Chevron	Chevron Canada Resources Limited
EDI	Ethylene Derivative Industry
EOG	Ethane Owners Group
ERCB	Energy Resources Conservation Board
IPAC	Independent Petroleum Association of Canada
m^3	cubic metres
m^3/d	cubic metres per day
Norcen	Norcen Energy Resources Limited
NOVA	NOVA, An Alberta Corporation
Project	Alberta Ethane/Ethylene Petrochemical Project
Shell	Shell Canada Limited
SPO	Straddle Plant Owners
Union Carbide	Union Carbide Ethylene Oxide/Glycol Company

ISSUE NUMBER 1: THE DETERMINATION OF ETHANE FACILITIES WHICH SHOULD BE PROTECTED BY OR BE PART OF THE POLICY

SUB-ISSUES	PETROCHEMICAL PROJECT	NATURAL GAS PRODUCERS
1.1 Existing upstreaming field plants.	The view of grandfathering of approved capacity, recovery factor, and gas sources was supported by AGEC, ANG, CEMJV, EDI, and SPO. SPO supported grandfathering provided an acceptable threshold level is set.	EOG rejected the grandfathering of approved capacity, recovery factor, and gas sources. Amoco and IPAC supported the idea. Chevron supported the idea provided the EOG package is not accepted in whole.
1.2 Existing non-upstreaming field plants.	The view of exempting the existing non-upstreaming field plants while no residue gas going to NOVA system was supported by AGEC, ANG, CEMJV, EDI, and SPO.	Exempting the existing non-upstreaming field plants was supported by all gas producers.
1.3 New upstreaming field plants.	New upstreaming field plants should be subject to policy. This view was supported by AGEC, ANG, CEMJV, EDI, and SPO.	The view of making new upstreaming field plants subject to the policy was supported by EOG, Amoco, Chevron, IPAC, Norcen, and Shell.
1.4 New non-upstreaming field plants.	Exempting new non-upstreaming field plants while no lean residue gas going to NOVA system was supported by AGEC, CEMJV, and SPO.	Exempting new non-upstreaming field plants was supported by Amoco, Chevron, EOG, Norcen, and Shell.
1.5 New field plants with ethane ownership retained.	New field plants which retain ownership of ethane through the straddle plants should be subject to the policy, in the view of AGEC.	While most producers did not make specific comment on this sub-issue, Shell suggested toll processing as a viable alternative to new field plants.
1.6 Existing straddle capacity.	AGEC, EDI, and SPO argued that the existing straddle capacity at today's efficiency level should be protected by policy to ensure 135 000 bbl/d (21 460 m^3/d) of ethane now and 150 000 bbl/d (23 850 m^3/d) later.	EOG, IPAC, Norcen, and Shell said that existing capacity should be affected by the policy but not protected.
1.7 Additional straddle capacity.	The Project stated that any additional straddle capacity that is required should be protected by the policy through upward adjustment of the threshold volume.	Chevron, EOG, Norcen, and Shell recommended that straddle plant expansions should not be protected by the policy.
1.8 Increase in straddle plant efficiency.	ANG indicated that increases in straddle plant efficiency should be protected through upward threshold volume adjustments.	Chevron, EOG, and Norcen argued for no protection of efficiency improvements through threshold volume. IPAC and Shell, however, recommended protection for some reasonable achievable efficiency level in the threshold level.
1.9 Ethylene manufacturing facilities.	AGEC, ANG, EDI, and SPO supported the protection of all existing and approved ethylene manufacturing facilities (AGE I, II, III, and debottlenecking).	EOG, IPAC, Norcen, and Shell argued for protection of AGE I and II as originally approved. Chevron indicated that the lesser of the approved capacity of AGE I and II, or their actual consumption, should be protected.
1.10 Ethylene upgrading facilities.	EDI and SPO supported protection of ethylene upgrading facilities in Alberta. EDI argued that both new and existing plants should be protected.	Chevron, EOG, IPAC, Norcen, and Shell opposed any protection for ethylene upgrading facilities other than as supplied by AGE I and II.
1.11 Ethane marketing.	AGEC, ANG, CEMJV, EDI, and SPO recommended that the volume of ethane marketed by CEMJV should be protected by the threshold volume. AGEC argued that ethylene exports should also be protected.	None of the gas producers supported the protection of ethane marketing through the threshold volume.
1.12 Duration of protection.	AGEC submitted that ethane should be protected for the Project's use for 20 years of facility life or contract life. SPO opted for no expiry of the protection while ANG recommended that protection continue at least until 2008.	Chevron, EOG, IPAC, and Norcen recommended a 5-year period of protection. EOG stated the 5-year protection should start from August 1987. Chevron said that it should start from the date when the ERCB decision is announced.

ISSUE NUMBER 2: THE PRINCIPLES THAT SHOULD BE USED IN DETERMINING THE THRESHOLD VOLUMES AND THE ACTUAL VOLUMES THEREBY DETERMINED

SUB-ISSUES	PETROCHEMICAL PROJECT	NATURAL GAS PRODUCERS
2.1 Commitment in Dowling Letters.	AGEC, ANG, EDI, and SPO submitted that a commitment was made to the Project for sufficient ethane at reasonable cost to fulfil the Project's ethane requirements.	Except for Shell, who stated that the Dowling letters gave no specific volume guarantees, other gas producers who made any remarks stated that the Dowling letters, at most, guaranteed ethane for AGE I and II.
2.2 Protection for expansion of ethylene manufacturing facilities.	See 1.9.	See 1.9.
2.3 Protection for ethane marketing volumes.	See 1.11.	See 1.11.
2.4 Protection for Cochin buffer requirements.	All Project participants recommended that this volume is required for ethylene export and should be part of the threshold volume.	EOG, IPAC, and Norcen stated that there should not be any protection for the Cochin Pipeline buffering requirements. Shell stated that there could be a minimum requirement protected by the policy for buffering purposes.
2.5 Protection for straddle plant expansion.	See 1.7.	See 1.7.
2.6 Protection for straddle plant efficiency improvements.	See 1.8.	See 1.8.
2.7 Measurement of the threshold volume at the inlets or outlets of straddle plants.	Project participants stated that the threshold volume should be measured at the outlet of the straddle system.	Chevron and Shell recommended that the threshold volume be measured at the inlet of the straddle system using a reasonable level of recovery factor. Other gas producers did not make specific comments regarding this issue.
2.8 Relate threshold volume to current demand for ethane by the Project.	AGEC, CEMJV, EDI, and SPO argued that the threshold volume level should not be related to the current demand. Threshold level should be met whether the Project is using the ethane or not. ANG stated that the threshold volume should be adjusted downward if the extracted ethane is not used by the Project.	Amoco recommended that the threshold volume should be flexible and reflect the actual Project requirements. All gas producers stated that the ethane should not be reinjected at the field if the Project is not using the ethane.
2.9 Supply risk due to low gas flows.	Except for CEMJV, who did not make any specific comments, all Project participants indicated that the Project accepted the risk of low gas flows due to deliverability problems and market demand.	EOG argued that shortfall of ethane due to low gas flow is a normal business risk that should be assumed by the Project. Shell and Norcen also supported the EOG position.
2.10 Supply risk due to low ethane content of gas flow caused naturally.	Except for CEMJV, who did not make specific comments on this issue, all Project participants submitted that they accepted the risk associated with natural fluctuations in gas inlet composition.	EOG said that a shortfall of ethane due to a natural low ethane content of the gas streams reaching the straddle system is a normal business risk that the Project was aware of at the time of plant construction.
2.11 Supply risk due to low ethane content caused by field plant upstreaming.	AGEC indicated that it was aware of the technical possibility of field plants extracting ethane upstream of the straddle system but did not believe the Government would allow it to be a major risk to the Project.	Chevron, EOG, and Norcen said that this issue is the main reason for the policy.

ISSUE NO. 2 (continued)

SUB-ISSUES	PETROCHEMICAL PROJECT	NATURAL GAS PRODUCERS
2.12 Expiry of threshold volume.	See 1.12.	See 1.12.
2.13 Recommended near-term threshold volume.	AGEC recommended that the threshold level should initially be set at 135 000 bbl/d (21 460 m^3/d). This volume is the sum of 95 000 bbl/d (15 100 m^3/d) for Joffre plants and 40 000 bbl/d (6 360 m^3/d) to be marketed by CEMJV. CEMJV, EDI, and SPO concurred with AGEC in this regard.	With some minor variations, all gas producers recommended a short-term level of threshold volume equal to the original design capacity of AGE I and II, which is about 75 000 bbl/d (11 925 m^3/d).
2.14 Recommended long-term threshold level.	AGEC recommended that after 1993, when debottlenecking and the third ethylene plant are complete, the threshold level should increase to 150 000 bbl/d (23 850 m^3/d). With the exception of ANG, who did not make any comments, other Project participants agreed with AGEC's recommendation.	Gas producers suggested that after 5 years the threshold volume and the Project's protection under the policy should expire. In the long run, free markets should prevail for both feedstock and product sales.

ISSUE NUMBER 3: THE DETERMINATION OF THE PROCEDURES FOR REQUIRING AND THE MECHANISM FOR ENSURING REINJECTION OR SUPPLY OF ETHANE TO STRADDLE PLANT SYSTEM

SUB-ISSUES	PETROCHEMICAL PROJECT	NATURAL GAS PRODUCERS
3.1 Priority of obligation to restore threshold volume.	In case of ethane shortfall from the set level of the threshold volume, AGEC recommended the last field plant built in Alberta should be the first plant to supply or reinject the ethane for restoring the threshold level. AGEC submitted that the royalty ethane from a new plant should be taken before the producer's share. SPO concurred with AGEC's recommendation. ANG suggested that field plants should supply or reinject ethane on a prorated basis.	Gas producers stated that royalty ethane should be used before taking producer ethane. Their specific priorizations are summarized below: Amoco: (1) royalty from new field plants, (2) non-royalty from new field plants, (3) royalty ethane from other plants. Chevron/Shell: (1) royalty ethane, (2) open market, (3) producer's ethane. EOG/IPAC: (1) open market, (2) royalty ethane, (3) producer's ethane. Norcen: (1) curtail export, (2) royalty ethane, (3) producer's ethane. All disagreed with last-built first-to-reinject concept.
3.2 Reinjection vs. supply in kind to restore threshold volume.	AGEC stated that it prefers the reinjection of ethane or by-passing at field plants. It argued that supply in kind may be constrained by unsuitability of ethane for AGE feedstock. ANG also rejected supply in kind because it is only possible for a few field plants. SPO submitted that it also prefers reinjection because supply in kind would affect its cost-of-service structure, unless the volume supplied in kind is "deemed" to have been produced at the straddle plants to maintain the ethane share of operating costs. AGEC concurred with the deeming concept proposed by SPO.	Chevron, IPAC, and Shell suggested that the option be left open to the ethane owner. EOG stated that, if practical, supply in kind be used; otherwise reinject ethane at the field plant gate.
3.3 Price of ethane provided to restore threshold volume.	AGEC recommended that the ethane reinjected to restore the threshold volume should be priced at its shrinkage value. The ethane provided in kind, however, should receive shrinkage value plus incremental cost of extraction at the straddle system. ANG, CEMJV, and EDI did not comment on this issue. SPO, however, agreed with AGEC's recommendation.	Amoco recommended that the price for ethane provided to restore the threshold should be on the basis of actual extraction and reinjection costs. Other gas producers recommended that the ethane be priced at its fair market value.
3.4 Price of other liquids accompanying ethane.	AGEC argued that propane-plus liquids reinjected with ethane should receive a shrinkage value as price. However, if these liquids are supplied in kind, they will receive their commodity value. SPO stated that the accompanying liquids should be treated the same as ethane.	Chevron suggested that the accompanying liquids should be returned to the producer in a manner satisfactory to him. Shell stated that payments for accompanying liquids should be deemed as a credit toward royalties payable, using contract prices.
3.5 Reinjected volume necessary to restore threshold volume.	AGEC estimated that 6.25 per cent of the reinjected ethane would not reach the straddle system. Therefore, sufficient ethane should be provided to restore the threshold level at the outlet of the straddle system. SPO argued that, for each barrel reinjected in the field, approximately 85 per cent will be recovered at Empress and 100 per cent would be recovered at Cochrane.	IPAC argued that it is inequitable to inject more ethane than can be recovered at the straddle plants. EOG argued that a mechanism to supply deficient volumes should be based on maximum recovery of ethane in the province.
3.6 Maintenance of threshold level.	See 2.9.	See 2.9.

SUB-ISSUES	PETROCHEMICAL PROJECT	NATURAL GAS PRODUCERS
3.7 Administration of reinjection requirements.	AGEC recommended that the Board should forecast, on an annual basis, the straddle system ethane availability to assess the likelihood of reinjection. The annual threshold volume would then be converted to monthly entitlements based on expected seasonal variation in gas throughputs. AGEC also recommended that the Board monitor daily the ethane availability to determine if reinjection is necessary. Underages or overages should be adjusted in the following month. The overage will be stored by the straddle system for 1 month at a cost to field plant producers. If the overage is not used within the following month, it will be disposed of by CEMJV. ANG suggested that the Board should direct a body or agency to administer the reinjection requirements and that NOVA or AEGS could be involved through their existing monitoring facilities. EDI also recommended that the Board should be legally authorized to administer the reinjection requirements. After implementation of the policy through legislation, the Board should set a task force to work out the details. Both CEMJV and SPO concurred with AGEC's recommendations.	Chevron recommended that if the royalty ethane is not sufficient to restore the threshold level, the following steps should be taken: 1. The Project provides a forecast of potential ethane prior to 1 October of each year to ERCB, showing shortfall. Also, evidence should be required to show that the shortfall cannot be made up through improvements in the recovery efficiency or system optimization or by contracting or for additional volume. 2. ERCB will hold meeting with affected parties if the request for reinjection is legitimate. 3. Field plant producers will decide among themselves which plants should provide the ethane to the system. If they do not agree by 1 December, ERCB will devise a suitable method to achieve this goal. 4. Comparison of actual ethane supply and forecast will be made by 1 February of the following year. If actual supply exceeded the forecast, then ethane in kind or fair market value of the ethane must be returned to the gas producer who reinjected the ethane, or the volume of ethane reinjected must be carried forward to make up possible shortfall in the current year. If actual supply were less than forecast, then a reverse procedure would be followed. EOG also recommended a similar procedure. It suggested that: 1. Based on the previous year's system performance, AGEC would provide a forecast of supply for the current year. 2. If insufficient, regulatory authority would provide a detailed supply-demand forecast for ethane for the current year. 3. Only deficient volumes in the forecast year would be provided. Gas producers will offer ethane at a negotiated price. 4. If insufficient, then royalty ethane should be used; if still insufficient, ethane should be provided in lieu of royalty on other gas components; if further volumes needed, ethane would be provided at owner's opportunity cost. 5. 90-day notice will be given for deficiencies. 6. In a year when deficient volumes are forecast, excess ethane volumes delivered would be a credit to future supply of deficient volumes.
3.8 Necessary period of notice of reinjection.	AGEC recommended 1-day notice and with some indication of expected duration of reinjection period. SPO concurred with AGEC.	EOG, Norcen, and Amoco recommended that ample notice, 60-90 days, be given for deficient volume deliveries and deficiencies be determined on an annual basis.

ISSUE NUMBER 4: PROCEDURES THAT SHOULD BE USED FOR THE EXPEDIENT REGULATORY PROCESSING OF APPLICATIONS FOR FIELD ETHANE EXTRACTION FACILITIES

SUB-ISSUES	PETROCHEMICAL PROJECT	NATURAL GAS PRODUCERS
4.1 Criteria for approving upstreaming applications.	SPO, ANG, and CEMJV recommended no change to the Board's past procedures for evaluating ethane extraction applications. AGEC suggested that there be a public interest test.	Applications for ethane extraction facilities should be handled in the same manner as other applications for removing gas liquids. All information required should be on a plant-only basis.
4.2 Public scrutiny of upstreaming applications.	There was general agreement that notice be given and that a hearing be held only if objections were received. SPO and CEMJV suggested notice be given only if the Board determined there might be an adverse impact on someone.	After the policy is implemented, publishing notice of the application should be sufficient for most cases. A hearing would be held only if contentious issues were identified. Such issues would not include any impact of upstreaming on the Project once the threshold volume was set.

ISSUE NUMBER 5: THE EXISTING AND POTENTIAL EFFICIENCY OF ETHANE EXTRACTION AT THE STRADDLE PLANTS, THE INVESTMENT REQUIRED TO ENHANCE EXTRACTION AND POTENTIAL LINKAGES WITH THRESHOLD VOLUMES

SUB-ISSUES	PETROCHEMICAL PROJECT	NATURAL GAS PRODUCERS
5.1 Current efficiency - input/output plots.	The input/output plots show that recovery efficiency decreases at the straddle plants as ethane is removed from the inlet gas because of field plants. Outlet ethane decreases as inlet ethane decreases but not as rapidly. For a given inlet ethane concentration, the outlet concentration is less with lower gas throughputs.	EOG disagreed with the validity of the input/output plots and the conclusions of the Handwerk study. In its opinion, based on other studies, the ethane recovery efficiency remains roughly constant over a wide range of inlet concentrations at the Empress plants.
5.2 Current efficiency - actual operation.	Efficiency is affected by operating mode relating to gas throughput; for example, use of Joule-Thompson valve, or use of one stage of expander rather than two stages. ANG pointed out its recovery efficiency is 87 per cent.	Stated that the current efficiency of the straddle plant system is lower than that of the newer field plants.
5.3 CO_2 specification in ethane.	Maximum of 2.5 per cent CO_2 permitted in product ethane. This specification lowers ethane recovery at Dome I and II plants. For example, increasing CO_2 in product from 5 to 6 per cent would increase ethane recovery by 2.5 per cent. ANG has a CO_2 removal unit in place.	No comment.
5.4 Reinjection or rejection of ethane at straddle system.	Reinjection, the preferred method to let ethane go, is ordered when there is no market for the ethane production. Other modes of operation when there is no market for ethane could be ethane rejection or by-passing of gas. Historically, no significant volumes of gas have been by-passed and the Project anticipates very little reinjection in future.	IPAC stated that field plant reinjection should not occur if the straddle plants are reinjecting/rejecting ethane. Chevron said that the straddle plants are by-passing or reinjecting ethane at significant rates which, if stored, could provide threshold volume protection for a whole year at AGEC's suggested threshold volume level.
5.5 Capacity of straddle system to process all available gas.	Some gas has been by-passed at Empress due to power failures but there are no capacity restrictions that exist. Gas containing about 5000 bbl/d (795 m^3/d) of ethane is forecast to be by-passed at Cochrane although ANG does not expect this to occur if its approved inlet is increased.	No comment.
5.6 Potential improvements in ethane extraction efficiencies and corresponding costs.	The Handwerk report estimated $54 x 10^6 for 20 000 bbl/d (3 180 m^3/d) additional ethane for ANG plant at Cochrane and Dome I and Petro-Canada plants at Empress. At the Petro-Canada plant, an additional 10 000 bbl/d (1 590 m^3/d) could be achieved through increased efficiency (53.2 to 78.0%) and a one-third expansion in throughput for $38 x 10^6. At Dome I, an additional 7 300 bbl/d (1 160 m^3/d) could be recovered with $12.5 x 10^6 investment. ANG estimated it would cost about $3.6 x 10^6 to recover an additional 3 700 bbl/d (588 m^3/d) ethane. Fluor Canada's report indicated that an additional 26 000 bbl/d (4 100 m^3/d) of ethane could be recovered at three Empress plants with an investment of $96.9 x 10^6. After adding the owner's cost, SPO indicated that total cost for these plants could reach $115.4 x 10^6.	EOG believes there is significant scope for efficiency enhancement at Empress. Shell stated that there should be a linkage between the threshold volume and the available straddle plant ethane as an incentive to increase the straddle plant recovery efficiencies. IPAC suggested that there is technology available to permit extraction efficiencies down to less than 1% ethane remaining in the residue stream. EOG and Chevron suggested that the technology proposed by SPO to increase the efficiency of the straddle plants was not the most appropriate and that the costs appeared to be high.
5.7 Effect on threshold volume of increased efficiency.	There was unanimous agreement within the Project that any recovery efficiency improvements at the straddle plants should be protected by an increase in the threshold volume.	EOG, Chevron, and Norcen agreed there should be no linkage between the threshold volume and efficiency improvements at the straddle plants. IPAC favoured a linkage but only to a maximum of AGE I and II design capacity. Shell also favoured a linkage, saying a lower threshold volume phasing out would encourage efficiency improvements at the straddle plants.

SUB-ISSUES	PETROCHEMICAL PROJECT	NATURAL GAS PRODUCERS
5.8 Effect of relative straddle/field recovery efficiencies on provincial ethane supply.	AGEC indicated that the relative straddle plant/field plant efficiencies were irrelevant to incremental ethane recovery. SPO said the Handwerk study showed that field plants produce only marginal incremental ethane for the province because the straddle plants would have recovered 0.85 barrel at Empress or 1 barrel at Cochrane for each barrel recovered in the field. ANG said that there should be some protection for a straddle plant owner who undertakes to increase recoverable ethane in the province.	Chevron stated that if the implemented policy encourages efficient ethane recovery, then there will be a sufficient supply such that a method to maintain a threshold volume will never have to be implemented.
5.9 Capacity of Alberta Ethane Gathering System.	Ethane pipeline capacity constraints downstream of Cochrane have caused some ethane reinjection at Waterton and Jumping Pound. SPO indicated that additional pumping capacity on the system would rectify the problem.	EOG stated that supply-side matters, such as contraints in the ethane distribution or storage system, should be considered in supplying the threshold volume. IPAC noted there is insufficient capacity in the western leg of the AEGS while Shell's suggestion was that the western leg must be expanded.

ISSUE NUMBER 6: ANY LEGISLATIVE CHANGES REQUIRED TO IMPLEMENT THE POLICY

SUB-ISSUES	PETROCHEMICAL PROJECT	NATURAL GAS PRODUCERS
6.1 Authority to order reinjection and 6.2 Administration of threshold volume.	AGEC, Union Carbide, and ANG indicated that the Oil and Gas Conservation Act and Regulations be amended to ensure the Board has the power to require reinjection of ethane and to provide for a penalty if the order is not complied with.	Except for IPAC and Amoco, who offered no comment, there was agreement that the Board does not currently have the right to order ethane reinjection or delivery in kind. Hence, changes to the Oil and Gas Conservation Act and Regulations would be necessary. Chevron suggested that a quasi-judicial mechanism be established to ensure fairness to affected producers. Shell and Norcen commented that legislative changes should not adversely affect ownership rights and that fair market prices should prevail for transferred ethane. Norcen added that legislative changes should reflect concern for simplicity and efficiency of administration.
6.3 Remove opportunity for objections on future applications.	Union Carbide agreed as long as the threshold volume is met. Other Project participants believed that any affected parties should continue to have the right to scrutinize applications and oppose them if necessary.	Chevron stated changes would be necessary to the Energy Resources Conservation Act and the Administrative Procedures Act which currently appear to make it impossible for the Board to not hold a hearing if an affected party insisted on one.
6.4 Ethane royalty.	No comment.	Chevron said that if only Crown royalty volumes were to be injected, then the Mines and Minerals Act on royalty regulations would have to be amended.